

DOCKETED

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Project Title:	Puente Power Project
TN #:	211570
Document Title:	Notice of Preliminary Determination of Compliance (PDOC)
Description:	PDOC from the Ventura County Air Pollution Control District for the Puente Power Project in Oxnard, Ventura County
Filer:	Jon Hilliard
Organization:	Ventura County Air Pollution Control District
Submitter Role:	Public Agency
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**Michael Villegas
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May 19, 2016

Mr. Jon R. Hilliard
Project Manager, STEP Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Subject: Notice of Preliminary Determination of Compliance (PDOC)
Puente Power Project (15-AFC-01)

Dear Mr. Hilliard:

Enclosed for your review and comment is the Ventura County Air Pollution Control District's (APCD) Preliminary Determination of Compliance (PDOC) for the Puente Power Project (Ventura County APCD Application No. 00013-370). This project proposes the installation of a nominal 262 megawatt natural gas-fired combustion turbine electrical generating facility at the existing Mandalay Generating Station (MGS) at 393 North Harbor Boulevard in Oxnard, CA.

This PDOC is being issued pursuant to Rule 26.9, "New Source Review – Power Plants". This project is expected to meet the requirements of Rule 26, "New Source Review", and all other applicable Ventura County APCD rules and regulations, including applicable state and federal requirements that the Ventura County APCD enforces. The PDOC includes conditions required to ensure compliance with these requirements.

By December 31, 2020, the Puente Power Project is proposed to "re-power" and replace two, older base-load electrical steam generating units, each rated at 215 megawatts; with a single combustion gas turbine, rated at 262 megawatts, that will operate as a peaking turbine that will be used when needed. The current Ventura County APCD Title V Permit for the Mandalay Generating Station allows MGS Unit 1 and MGS Unit 2 to each operate at a 100 percent capacity factor for 8,760 hours per year. The Puente Power Project turbine will be limited to operation of 2,150 hours per year, which equals a capacity factor of approximately 25 percent. If fully completed as proposed, the Puente Power Project will result in an annual electrical generating capacity reduction from 3,766,800 megawatt-hours per year to 563,300 megawatt-hours per year, which equals a reduction of approximately 85 percent.

As shown in this PDOC, if fully completed as proposed, the Puente Power Project will reduce the permitted emissions of the Mandalay Generating Station from 222.74 tons per year to 78.61 tons per year, which equals a permitted NOx emission reduction of approximately 65 percent. However, under Ventura County APCD emission calculation rules, the actual NOx emissions increase from this project has been calculated to be 29.93 tons per year. As required by Ventura County APCD Rule 26.2, "New Source Review – Requirements", this NOx emission increase will be offset, at a tradeoff ratio of 1.3 to 1, with Emission Reduction Credits totaling 38.91 tons per year.

Pursuant to Rules 26.9.F and 26.7.B.1, the notice of preliminary decision for this project will be published in the Ventura County Star (in English) and the Vida Newspaper (in Spanish) by no later than 10 days from the date of this letter. This notice will also be posted on our website (www.vcapcd.org) in English, Spanish, Tagalog, and Mixteco. Written comments on this project are to be submitted within the 30-day period which begins on the date of the newspaper publication of the public notice.

If you have any questions, or wish to discuss this matter in further detail, please contact me at (805) 645-1421 or by email at kerby@vcapcd.org.

Sincerely,



Kerby E. Zozula, Manager
Engineering Division

Enclosures

Copies (via email): George Piantka, NRG (George.Piantka@nrg.com)
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VENTURA COUNTY APCD PRELIMINARY DETERMINATION OF COMPLIANCE

PUENTE POWER PROJECT CEC APPLICATION FOR CERTIFICATION DOCKET NUMBER 15-AFC-01

Facility Name:	Puente Power Project
Mailing Address:	NRG Energy Center Oxnard LLC 5790 Fleet Street, Suite 200 Carlsbad, CA 92008
Facility Address:	NRG California South LP Mandalay Generating Station 393 North Harbor Blvd Oxnard, CA 93035
NRG Contact:	George L. Piantka, PE Sr. Director, Regulatory Environmental Services 760-710-2156 Phone 760-710-2158 FAX
VCAPCD Engineer:	Kerby E. Zozula Engineering Division Manager Ventura County APCD 805-645-1421 Phone 805-645-1444 FAX
Date Issued:	May 19, 2016
VCAPCD Application:	Rule 26.9 - DOC/Authority to Construct No. 00013-370
Application Submitted:	March 26, 2015
Deemed Complete:	May 28, 2015
Application Revised:	December 10, 2015

I. Project Proposal and Project Summary

The Puente Power Project (P3), owned by NRG Energy Center Oxnard LLC (NRG), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of a new H-Class simple-cycle natural gas fired combustion turbine generator (CTG) with a nominal rating of 262 MW and a new emergency diesel electricity generator engine with a rating of 779 BHP. The new turbine and the new diesel engine, along with other ancillary equipment, will be called the Puente Power Project (P3). The Puente Power Project will be located at the existing Mandalay Generating Station (MGS). The current Mandalay Generating Station facility equipment list and permitted emissions are included in Appendix A – Current Permitted Emissions.

This DOC is being issued pursuant to VCAPCD Rule 26.9, New Source Review - Power Plants. The Puente Power Project is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. The Puente Power Project filed an Application For Certification with the CEC on April 15, 2015 (AFC Docket No. 15-AFC-01).

The project consists of replacing MGS Unit 2 (1,990 MMBTU/Hr, 215 MW net, Babcock and Wilcox Steam Generator natural gas fired electric utility boiler), with a new natural gas fired General Electric H-Class simple-cycle CTG (Model GE 7HA.01, 262 MW net nominal). MGS Unit 2 will be permanently shut down at the end of the commissioning period for the proposed new gas combustion turbine generator. MGS Unit 1 may be operational after the new CTG is operational, but will be permanently shut down prior to December 31, 2020. Ultimately, the Puente Power Project is designed to replace both MGS Unit 1 and MGS Unit 2.

P3 will also be replacing the existing 201 BHP diesel emergency electricity generator engine with a new 779 BHP diesel emergency electricity generator engine. An existing 154 BHP diesel emergency fire water pump engine will also be shut down. The remainder of the NRG Mandalay Generating Station facility will remain unchanged: including the 2510 MMBTU/Hr (130 MW) natural gas-fired peaker combustion turbine (MGS Unit 3), and various ancillary facilities. The new P3 CTG will utilize existing natural gas fuel lines and electrical distribution lines.

The Mandalay Generating Station currently has a Part 70 (Title V) Permit No. 00013 and a Title IV Acid Rain Permit No. 00013. As required by VCAPCD Rule 33.5, Part 70 Permits - Timeframes for Applications, Review and Issuance, prior to operation of the new P3 CTG, NRG will submit an application to amend their Part 70 Permit and Title IV Acid Rain Permit to include the Puente Power Project if approved by the CEC.

The ultimate design of the Puente Power Project is proposed to “re-power” and replace two, older base-load electrical steam generating units, each rated at 215 MW, with a single new combustion gas turbine, rated at 262 MW net nominal, that will operate as a peaking turbine to be used when needed. The current Title V permit for the Mandalay Generating Station allows MGS Unit 1 and MGS Unit 2 to each operate at a 100 percent capacity factor for 8,760 hours per year (24 hours per day over 365 days per year). The Puente Power Project CTG will be limited to operation of 2,150 hours per year, which equals a capacity factor of approximately 25 percent. If fully completed as proposed, the Puente

Power Project will therefore result in an annual electrical generating capacity reduction from 3,766,800 MW-hrs per year to 563,300 MW-hrs per year, which equals a reduction of approximately 85 percent.

As shown in this DOC, if fully completed as proposed, the Puente Power Project will reduce the permitted NO_x emissions of the Mandalay Generating Station from 222.74 tons per year to 78.61 tons per year, which equals a permitted NO_x emission reduction of approximately 65 percent when both MGS Unit 1 and MGS Unit 2 will be permanently shut down by December 31, 2020. However, under Ventura County APCD rules, there will be a NO_x emissions increase from the Puente Power Project of 29.93 tons per year calculated based on the post-project potential to emit for the new units minus the pre-project actual emissions for the existing units being replaced. As required by Ventura County APCD Rule 26.2, New Source Review - Requirements, this NO_x emission increase will be offset, at a tradeoff ratio of 1.3 to 1, with Emission Reduction Credits totaling 38.91 tons per year.

VCAPCD Rule 59, Electrical Power Generating Equipment - Oxides of Nitrogen Emissions, currently limits NO_x emissions from MGS Unit 1 and MGS Unit 2 to a rate of 0.10 pounds of NO_x per megawatt-hour. The Puente Power Project turbine will emit NO_x at a rate of 0.09 pounds of NO_x per megawatt-hour as limited by this DOC and the best available control technology (BACT) requirements of VCAPCD Rule 26.2, New Source Review - Requirements. This equals a decrease in the allowable NO_x emission rate of 10 percent during normal operations.

To put the NO_x emissions from the proposed Puente Power Plant into perspective, many facilities in Ventura County are equipped with backup emergency diesel engines to generate electricity in case of a grid power failure. NO_x emissions from emergency diesel engines are significantly greater than the NO_x emissions from natural gas-fired combustion turbines. For example, a typical single hospital in Ventura County is equipped with approximately 2.5 megawatts (2,500 kilowatts) of emergency diesel engines that may emit NO_x at a diesel engine Tier 2 emission rate of approximately 6 grams of NO_x per kilowatt-hour, which is equivalent to a total mass rate of about 33 pounds of NO_x per hour. This is equivalent to 13.2 pounds of NO_x per megawatt-hour for the emergency diesel engines, as compared to an emission rate of 0.09 pounds of NO_x per megawatt-hour from the proposed Puente Power Project. Therefore, if required to operate in the event of a grid power failure, these emergency diesel engines at a single Ventura County hospital will emit NO_x at a pounds per megawatt-hour rate of almost 147 times the NO_x emissions rate from the proposed Puente Power Project. Under normal operation, the proposed Puente Power Project will emit NO_x at a mass rate of 23.73 pounds per hour, which is less than the NO_x emissions from the emergency diesel engines at just one typical hospital in Ventura County (33 pounds per hour). This is true even though the power output of the proposed Puente Power Project will be about 100 times greater than the power output of the emergency diesel engines at typical single Ventura County hospital (262 megawatts as compared to 2.5 megawatts). From an air quality perspective, a natural gas-fired peaking turbine is the preferred alternative to operating backup emergency diesel engines.

II. Applicable Rules and Regulations

Rule 26.2 - New Source Review – Requirements

Rule 26.6 - New Source Review – Calculations

Rule 26.7 - New Source Review - Notification

Rule 26.9 - New Source Review - Power Plants

Rule 26.11 - New Source Review – ERC Evaluation at Time of Use

Rule 26.12 - Federal Major Modifications

Rule 26.13 - New Source Review - Prevention of Significant Deterioration (PSD)

The applicant has determined that PSD does not apply to the proposed Puente Power Project. Rule 26.13 implements the requirements of 40 CFR 52.21 – Prevention of Significant Deterioration (PSD). This rule has not been approved by U.S. EPA. As such, any implementation of PSD requirements, including applicability determinations and/or determination of compliance with PSD requirements can only be performed by U.S. EPA. The Ventura County ACPD does not have the authority to implement and enforce the requirements of PSD at this time. Since the applicant has stated that PSD does not apply, this DOC does not include a discussion or calculations of greenhouse gases (GHGs).

Rule 29 – Conditions on Permits

Rule 33.5 – Part 70 Permits – Timeframes for Applications, Review and Issuance

Rule 34 – Acid Deposition Control

Rule 50 – Opacity

Rule 51 - Nuisance

Rule 52 - Particulate Matter - Concentration (Grain Loading)

Pursuant to Sections B.1.f and B.1.g of Rule 52, the rule does not apply to the proposed gas turbine or internal combustion engine since the equipment will combust only gaseous or liquid fuels respectively and emit only combustion products.

Rule 53 - Particulate Matter - Process Weight

Pursuant to Sections B.1.f and B.1.g of Rule 53, the rule does not apply to the proposed gas turbine or internal combustion engine since the equipment will combust only gaseous or liquid fuels respectively and emit only combustion products.

Rule 54 - Sulfur Compounds

Rule 55 – Fugitive Dust

Rule 57.1 - Particulate Matter Emissions From Fuel Burning Equipment

Rule 64 - Sulfur Content of Fuels

Rule 68 Carbon Monoxide

Pursuant to Sections B.1.f and B.1.g of Rule 68, the rule does not apply to the gas turbine or the engine since the units combust only gaseous fuel and liquid fuel respectively and emit only combustion products.

Rule 74.9 - Stationary Internal Combustion Engines

Rule 74.23 - Stationary Gas Turbines

Rule 103 - Continuous Monitoring Systems

California Health & Safety Code 42301.6 - School Notice

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

Public Resources Code 21000-21177 - California Environmental Quality Act (CEQA) - California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387 CEQA Guidelines

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

- 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines
- 40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units
- 40 CFR Part 63, Subpart YYYY, National Emission Standard for Hazardous Air Pollutants (NESHAP) for Combustion Turbines
This rule applies to combustion turbines installed at major sources of hazardous air pollutants (HAPs). This turbine is not subject to the subpart because the stationary source is not a major source of HAPs. Section 63.6090 defines an affected source for Subpart YYYY as “any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions.” As shown in Appendix H - Hazardous Air Pollutant Stationary Source Potential to Emit, the HAP emissions from the proposed stationary source are less than the major source threshold for a single HAP of 10 tons per year and less than the major source threshold for combined HAPs of 25 tons per year. Note that ammonia and propylene are considered to be toxic air contaminants but are not defined as EPA HAPs.
- 40 CFR Part 63 Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE)
- 40 CFR Part 64, Compliance Assurance Monitoring
- 40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention
- 40CFR Part 75, Continuous Emission Monitoring (CEMS)

III. Project Location

The Puente Power Project (P3) will be installed at a site within NRG’s existing Mandalay Generating Station (MGS) located at 393 North Harbor Boulevard in Oxnard, California.

IV. Process Description

The Puente Power Project (P3), owned by NRG, requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of a new H-Class simple-cycle natural gas fired combustion turbine generator (CTG) and a new emergency diesel generator engine. The new turbine and the new diesel engine along with other ancillary equipment will be called the Puente Power Project (P3).

The project consists of replacing MGS Unit 2 (1,990 MMBTU/Hr, 215 MW net, Babcock and Wilcox Steam Generator natural gas fired electric utility boiler) with a new natural gas fired General Electric (GE) H-Class simple-cycle CTG (Model GE 7HA.01, 262 MW net nominal). MGS Unit 2 will be permanently shut down at the end of the commissioning period for the proposed gas turbine engine. MGS Unit 1 will operate after the new CTG is operational, but will be permanently shut down prior to December 31, 2020. Even though MGS Unit 1 will eventually be shut down, this evaluation assumes MGS Unit 1 remains operational and the emissions associated with MGS Unit 1 are still accounted for in the stationary source emissions for this project.

P3 will also be replacing the existing 201 BHP diesel emergency generator engine with a new 779 BHP diesel emergency electricity generator unit. An existing 154 BHP diesel emergency fire water pump engine will be shut down. The remainder of the NRG facility

will remain unchanged: including the 2510 MMBTU/Hr (130 MW) natural gas-fired peaker combustion turbine (MGS Unit 3), and various ancillary facilities. The current facility permitted emissions are in Appendix A – Current Permitted Emissions.

V. Equipment Listing

New Combustion Turbine Generator (CTG):

General Electric (GE) 7HA.01 Combustion Turbine Generator (CTG) set, rated at 262 MW net nominal, Serial No. to be determined, simple cycle, equipped with dry low-NO_x combustion, a Selective Catalytic Reduction (SCR) system with aqueous ammonia injection for NO_x control and an oxidation catalyst for CO control

The turbine is a simple-cycle turbine; there is no heat recovery steam generator. The proposed unit is a GE 7HA.01 Model. The turbine is designed to fire natural gas only. The net heat rate is 9039 BTU/kWh (LHV). There is no bypass stack. The dry low NO_x combustors achieve lower NO_x emission through the design of the combustors and fuel injection nozzles. This design optimizes the mixing of combustion air and fuel at peak flame temperatures resulting in low NO_x emissions. The exhaust is then sent through an oxidation catalyst and SCR system.

Oxidation Catalyst:

The proposed oxidation catalyst unit is a BASF Camet system with the following dimensions: 25'W x 100'H x 0.6'D. The minimum and maximum operating temperatures for the oxidation catalyst are 300 and 1,250 degrees Fahrenheit. The oxidation catalyst is located upstream of the SCR unit which is located just upstream of the exhaust stack.

SCR System:

The proposed SCR unit is a Cormetech Model CM21HT unit with the following exterior dimensions: 25'W x 100'H x 1'D. It is a high temperature catalyst that is designed to operate without turbine exhaust cooling. The minimum and maximum operating temperatures for the SCR catalyst are 300 and 1,050 degrees Fahrenheit.

Continuous Emission Monitoring System:

A Continuous Emissions Monitoring System (CEMS) is proposed for monitoring and recording NO_x and CO emissions from the turbine.

Emergency Internal Combustion Engine:

The project also includes an emergency internal combustion engine. The engine is diesel fired and will power the auxiliary electricity generator equipment required to shut down the plant in the event that there is a power outage. The proposed unit is a 779 BHP Caterpillar engine that produces 500 KW of emergency electric power. The engine is required to be certified to meet U.S. EPA Tier 4-Final emission standards.

The engine will only be used during emergencies when there is no power available from the electrical grid. The engine will be limited to a total of 50 hours per year for maintenance and readiness testing purposes.

Support Equipment:

The facility will have additional support equipment that is exempt from permit pursuant to

Rule 23, Exemptions From Permit. This equipment includes an electric powered fuel gas compressor, a water demineralizer, water storage tank, transformers, and one aqueous ammonia storage tank. This equipment is not subject to VCAPCD permit requirements, but is subject to general prohibitory rules such as Rule 50, Opacity, and Rule 51, Nuisance.

VI. Emission Control Technology Evaluation

The CTG will be equipped with dry low NO_x (DLN) combustors. DLN combustors achieve a NO_x emission rate of 25 ppmvd @ 15% O₂ without the use of water or steam injection. The low NO_x emission rate is accomplished by the design of the combustors and fuel injection nozzles which optimizes the mixing of combustion air and fuel at peak flame temperatures. This results in low NO_x emissions.

The proposed CTG will be equipped with an oxidation catalyst for CO control, and a selective catalytic reduction (SCR) system for NO_x control.

The proposed oxidation catalyst unit is a BASF Camet system with the following dimensions: 25'W x 100'H x 0.6'D. The minimum and maximum operating temperatures for the oxidation catalyst are 300 and 1,250 degrees Fahrenheit. The oxidation catalyst is located upstream of the SCR unit which is located just upstream of the exhaust stack.

The proposed SCR unit is a Cormetech Model CM21HT unit with the following exterior dimensions: 25'W x 100'H x 1'D. The SCR system consists of ammonia injection in the CTG exhaust upstream of the catalyst and a catalyst bed. The ammonia reduces NO_x to N₂ and O₂ in the presence of the catalyst. The SCR catalyst is a high temperature catalyst. The minimum and maximum operating temperatures for the SCR catalyst are 300 and 1,050 degrees Fahrenheit. Unreacted ammonia (ammonia slip) will be present in the CTG engine exhaust. Ammonia slip will be limited to 5 ppmvd @ 15% O₂. The SCR system reduces the CTG NO_x emissions by approximately 90% from 25 ppmvd to 2.5 ppmvd @ 15% O₂.

The proposed emergency IC diesel engine will be certified to meet US EPA Tier 4 final emission requirements.

VII. Emission Calculations

The emission calculations below are performed pursuant to the requirements of Rule 26.6 New Source Review - Calculations. Based on Rule 29, Conditions on Permits, and Rule 42, Permit Fees, the emissions of ROC, NO_x, PM₁₀, SO_x, CO, and NH₃ have been calculated in the units of tons per year and pounds per hour for the Puente Power Project CTG and emergency diesel engine.

Assumptions:

All PM₁₀ emissions from the turbine are assumed to be PM_{2.5}

Natural gas fuel sulfur limit limited to 0.75 grain per 100 scf (0.0021375 lb SO_x/MMBTU)

Natural gas HHV = 1018 BTU/scf (nominal value from AFC Table 4.1-15)

Combustion "F" factor of 8710 dscf/MMBTU for natural gas (EPA Method 19)

Molecular weight (ROC) = 16 lb/lb-mole for methane

Molecular weight (NO_x) = 46 lb/lb-mole for nitrogen dioxide

Molecular weight (CO) = 28 lb/lb-mole
Molecular weight (NH₃) = 17 lb/lb-mole

Worst case CTG hourly emissions are during startup/shutdown/restart hour
Fuel Usage Maximums = 2,572 MMBTU/Hr (2.53 MMscf/Hr)
Annual emissions based on 200 startups, 200 shutdowns, 1,750 hours normal operation
Startup = 1 hour
Shutdown = 1 hour
Worst case hour = 30 minutes startup + 12 minutes shutdown + 18 minutes startup
Steady state emissions values per manufacturer guarantee (see GE letter) Appendix B
Emergency engine limited to 50 hrs/yr non-emergency use for maintenance and readiness testing, with no hours limit on actual emergency use.
Baseline period 2012-2013 – Based on Rule 26.6.C, this two consecutive year period was determined to be the most representative as it best reflects current electricity market.
The applicant has supplied manufacturer emission data for CTG startup and shutdown emissions in Appendix B.

Rule 26.6 B – Potential to Emit

New Combustion Turbine Generator (CTG):

The CTG has various states of operation: startup, shutdown, and normal operation. The CTG has different emission factors associated with the various states of operation. NRG has proposed operation limits for the facility based on 200 startups, 200 shutdowns, and 1,750 hours of normal full load operation on an annual basis. The worst case daily operations the CTG may have four startup/shutdown cycles with the rest of the day at full load operation. The worst hourly emissions would occur when there is a startup then shutdown then another startup all within the same hour. While this worst case scenario is possible, it would be infrequent. The manufacturer of the CTG, General Electric, has provided hourly emission rates for startup and shutdown operation, see below. During startups and shutdowns the SCR system and the oxidation catalyst are not effective at reducing NO_x and CO emissions as the exhaust temperature is not high enough for effective emissions control.

The maximum hourly emissions for startup consist of a maximum of 30 minutes at the higher startup emission rate followed by the remaining 30 minutes at the normal operation emission rate. The maximum hourly emissions for shutdown consist of a maximum of 12 minutes at the shutdown emission rate preceded by 48 minutes at the normal operation emission rate. Table VII-1 below shows how the hourly startup and hourly shutdown emissions were calculated:

Table VII - 1

Startup and Shutdown Maximum Hourly Emissions (lbs)						
Pollutant	Startup Emissions			Shutdown Emissions		
	Startup +	Normal Operation =	Maximum Hourly Startup	Shutdown +	Normal Operation =	Maximum Hourly Shutdown
Duration (min)	30	30	60	12	48	60
ROC	17.00	3.30	20.30	25.00	5.28	30.28
NOx	87.00	11.87	98.87	4.00	18.98	22.98
PM ₁₀	3.70	5.05	8.75	1.50	8.08	9.58
SOx	2.75	2.75	5.50	1.10	4.40	5.50
CO	167.00	11.55	178.55	145.00	18.48	163.48
NH3	N/A	8.77	8.77	N/A	14.02	14.02

The worst case startup/shutdown emissions would occur if the CTG undergoes a 30-minute startup, followed by a 12-minute shutdown, and then is restarted for the remaining 18 minutes. Table VII-2 below shows how the hourly startup/shutdown/restart emissions were calculated:

Table VII - 2

Startup/Shutdown/Restart Maximum Hourly Emissions (lbs)				
Pollutant	Startup +	Shutdown +	Restart (Startup) =	Maximum Hourly Startup/ Shutdown/ Restart Emissions
Duration (min)	30	12	18	60
ROC	17.00	25.00	10.20	52.20
NOx	87.00	4.00	52.20	143.20
PM ₁₀	3.70	1.50	2.22	7.42
SOx	2.75	1.10	1.65	5.50
CO	167.00	145.00	100.20	412.20
NH3	N/A	N/A	N/A	N/A

The maximum startup and shutdown hourly emissions are summarized in Table VII-3 below:

Table VII - 3

Startup and Shutdown Maximum Hourly Emissions			
Pollutant	Startup	Shutdown	Startup/Shutdown/ Restart
	Pounds Per Hour	Pounds Per Hour	Pounds Per Hour
ROC	20.30	30.28	52.20
NO _x	98.87	22.98	143.20
PM ₁₀	8.75	9.58	7.42
SO _x	5.50	5.50	5.50
CO	178.55	163.48	412.20
NH ₃	8.77	14.02	n/a

Table VII - 4

Startup and Shutdown Annual Emissions				
Pollutant	Startup		Shutdown	
	Pounds Per Hour	Tons Per Year (200 Startups/yr)	Pounds Per Hour	Tons Per Year (200 Shutdowns/yr)
ROC	20.30	2.03	30.28	3.03
NO _x	98.87	9.89	22.98	2.30
PM ₁₀	8.75	0.88	9.58	0.96
SO _x	5.50	0.55	5.50	0.55
CO	178.55	17.86	163.48	16.35
NH ₃	8.77	0.88	14.02	1.40

During normal operation, the exhaust from the CTG is sent through the oxidation catalyst and SCR system. In the oxidation catalyst section, incompletely combusted organic compounds and carbon monoxide are further oxidized on the catalyst and converted primarily to carbon dioxide (CO₂) and water (H₂O). In the SCR section, aqueous ammonia (NH₃) is introduced into the exhaust stream through lances inserted into the exhaust ducting. The ammonia mixes with the exhaust gas and reacts with NO_x on the surface and interior of the catalyst to produce nitrogen gas (N₂) and water (H₂O). Some residual ammonia, also known as "ammonia slip", remains in the exhaust gas. Normal operations are expected to occur 1,750 hours per year. See emission factors, emission factor basis,

and the calculated pounds per hour emissions at the steady state normal operational load below.

ROC, NO_x, CO, and NH₃ ppmvd emission factors are BACT requirements and / or proposed by the applicant. The PM₁₀ emission factors are based on the turbine manufacturer's data and proposed by the applicant. The SO_x emission factor limit is based on a fuel sulfur content of 0.75 gr S/100 scf as proposed by the applicant.

Table VII - 5

New Turbine Emission Calculations - Normal Operation				
Pollutant	Emission Factor	Emission Factor Basis	Pounds Per Hour (@ 2.53 MMscf/hr)	Tons Per Year (1,750 hr/yr)
ROC	2.61 lb/MMscf	2.0 ppmvd (BACT)	6.60	5.78
NO _x	9.38 lb/MMscf	2.5 ppmvd (BACT)	23.73	20.76
PM ₁₀	N/A	10.1 lb/hr per GE	10.10	8.84
SO _x	0.0021375 lb/MMBtu	Applicant Proposed Limit	5.50	4.81
CO	9.13 lb/MMscf	4.0 ppmvd (Rule 29)	23.10	20.21
NH ₃	6.93 lb/MMscf	5 ppmvd (BACT)	17.53	15.34

The lb/MMscf emission factors for ROC, NO_x, CO, and NH₃ are calculated based on the following equation pursuant to EPA Method 19:

$$\text{lb/MMscf} = (F)(MW)(20.9/20.9-15)(\text{lbmole}/385 \text{ dscf})(\text{ppmv}@15\%\text{O}_2/10^6)(1018 \text{ MMBTU/MMscf})$$

where F= f-factor
 MW = Molecular weight

Maximum hourly emissions occur when there is a startup/shutdown/restart sequence. This sequence is not planned for the facility but could happen. This up/down/up sequence represents the worst case maximum hourly emissions.

The maximum annual emissions will occur with 200 startup hours, 200 shutdown hours, and 1,750 hours steady state operation. The emissions are tabulated in Table VII-6 below:

Table VII - 6

New Turbine Emission Calculations – Maximum Permitted Emissions Hourly and Annual Operations		
Pollutant	Hourly	Annual
	Pounds Per Hour	Tons Per Year
ROC	52.20	10.84
NO _x	143.20	32.95
PM ₁₀	10.10	10.68
SO _x	5.50	5.91
CO	412.20	54.42
NH ₃	17.53	17.62

CTG Commissioning Calculations

The application includes information on the commissioning of the turbine. The SCR with ammonia injection and oxidation catalyst control systems will not be operable during a portion of the commissioning period as the control systems are going through a commissioning period as well. These systems do not alter the PM or SO_x emissions; therefore, only the ROC, NO_x, and CO emissions will be affected. Some commissioning tests will result in uncontrolled ROC and NO_x emissions and some tests result in partially controlled emissions. These emissions and the expected total for the commissioning process are shown in Table VII-7 below:

Table VII - 7

New Turbine Commissioning Emissions		
Pollutant	Maximum Commissioning Emissions (lbs/hr)	Total Commissioning Emissions (tpy)
ROC	164.10	3.52
NO _x	246.30	11.70
CO	1973.00	31.74

NRG has provided an estimated commissioning schedule for the turbine. The schedule is in Appendix C. The emissions from the commissioning process will be accounted for in

the total annual emissions from the CTG. NRG will ensure that the total annual emissions from the facility do not exceed their annual permitted emissions including during the commissioning process.

New Emergency Internal Combustion Engine:

The emissions for the 779 BHP Caterpillar are based on full load operation at 50 hours per year. The engine will have a 50 hour per year limit for non-emergency usage for maintenance and readiness testing. There will not be an hours per year usage limit for actual emergencies.

The emission factors are based on the Final Tier 4 standards for engines in service as a generator. The permitted emissions are shown in Table VII-8 below:

Table VII - 8

New 779 BHP Emergency Engine Emission Calculations				
Pollutant	Emission Factor (g/bhp-hr)	Emission Factor Basis	Tons Per Year (50 hr/yr)	Pounds Per Hour
ROC	0.14	EPA Tier 4 final non-road diesel standards	0.01	0.24
NO _x	0.50	EPA Tier 4 final non-road diesel standards	0.02	0.86
PM ₁₀	0.02	EPA Tier 4 final non-road diesel standards	0.00	0.03
SO _x	0.0051	Very low sulfur fuel (15 ppmw) mass balance - see below	0.00	0.008
CO	2.6	EPA Tier 4 final non-road diesel standards	0.11	4.48

$$\frac{0.000015 \text{ lb} - S}{\text{lb} - \text{fuel}} \times \frac{7.1 \text{ lb} - \text{fuel}}{\text{gallon}} \times \frac{2 \text{ lb} - SO_2}{1 \text{ lb} - S} \times \frac{1 \text{ gal}}{137,000 \text{ Btu}} \times \frac{1 \text{ bhp input}}{0.35 \text{ bhp out}} \times \frac{2,542.5 \text{ Btu}}{\text{bhp} - \text{hr}} \times \frac{453.6 \text{ g}}{\text{lb}} = 0.0051 \frac{\text{g} - SO_x}{\text{bhp} - \text{hr}}$$

Existing Steam Boilers (MGS Unit 1 & MGS Unit 2):

There are two existing natural gas fired electric utility steam boilers at the NRG facility. They are both 1,990 MMBTU/Hr (215 MW) Babcock and Wilcox natural gas steam boilers. As previously discussed one steam steamboiler (MGS Unit 2) will be permanently shut down at the end of the new turbine commissioning period. The other boiler (MGS Unit 1) may be operational up until December 31, 2020 when it will be permanently shut down.

The potential emissions from the existing MGS Unit 1 and Unit 2 are from the permitted emissions summary for the MGS (see Appendix A) and are shown in Table VII-9 below:

Table VII - 9

Permitted Emissions for Existing Natural Gas Fired Steam Boilers (MGS Unit 1 & MGS Unit 2 each)			
Pollutant	Emission Factor (lb/MMscf)	Pounds Per Hour	Tons Per Year
ROC	1.40	2.66	11.62
NO _x	10.66	20.21	88.49
PM ₁₀	2.50	4.74	20.76
SO _x	0.60	1.14	4.98
CO	40.0	75.81	332.05

The existing CTG MGS Unit 3 will continue to be operated as a peaking turbine. It is connected to a different portion of the electrical grid as compared to existing MGS Unit 1 and Unit 2 and the proposed Puente Power Project CTG. The potential emissions from the existing CTG MGS Unit 3 are from the permitted emissions summary for this facility (see Appendix A) and are shown in Table VII-10 below. These permitted emissions represent a permit operational limit of approximately 83 hours per year.

Table VII - 10

Permitted Emissions for Existing Natural Gas Fired Turbine (MGS Unit 3)			
Pollutant	Emission factor (lb/MMscf)	Pounds Per Hour	Tons Per Year
ROC	7.56	18.07	0.75
NO _x	462.00	1104.41	45.64
PM ₁₀	20.30	48.53	2.01
SO _x	0.60	1.43	0.06
CO	115.50	276.10	11.41

Existing Emergency IC Engines

The two existing emergency engines provide emergency electrical power and also emergency firewater for the facility. Both engines are limited to 20 hours per year of non-emergency operation for maintenance and testing. The potential emissions from the

existing IC engines are from the permitted emissions summary for this facility (see Appendix A) and are shown in Tables VII-11 and VII-12 below:

Table VII - 11

Permitted Emissions for MGS Existing 154 BHP emergency engine		
Pollutant	Pounds Per Hour	Tons Per Year
ROC	0.04	0.00
NO _x	0.51	0.05
PM ₁₀	0.04	0.00
SO _x	0.01	0.00
CO	0.11	0.01

Table VII - 12

Permitted Emissions for MGS Existing 201 BHP emergency engine		
Pollutant	Pounds Per Hour	Tons Per Year
ROC	0.05	0.00
NO _x	0.67	0.07
PM ₁₀	0.05	0.00
SO _x	0.01	0.00
CO	0.15	0.01

The following Tables VII-13 and VII-14 summarize the current Mandalay Generating Station permitted emissions (pre-project) and the proposed Mandalay Generating Station permitted emissions if the Puente Power Project is implemented as proposed (post-project):

Table VII - 13

Summary of Facility Pre-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	NO_x	PM₁₀	SO_x	CO	NH₃
MGS Unit 1 Steam Boiler	11.62	88.49	20.76	4.98	332.05	39.02
MGS Unit 2 Steam Boiler	11.62	88.49	20.75	4.98	332.04	39.01
MGS Unit 3 CTG	0.75	45.64	2.01	0.06	11.41	0
MGS 154 BHP Emergency Engine	0	0.05	0	0	0.01	0
MGS 201 BHP Emergency Engine	0	0.07	0	0	0.01	0
P3 New 262 MW Turbine	0	0	0	0	0	0
P3 New 779 BHP Engine	0	0	0	0	0	0
Pre-Project Total Stationary Source	23.99	222.74	43.52	10.02	675.52	78.03
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As seen in Table VII-13 above, pre-project the facility is a major source for NO_x only.

Table VII - 14

Summary of Facility Post-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	NO_x	PM₁₀	SO_x	CO	NH₃
MGS Unit 1 Steam Boiler	11.62	88.49	20.76	4.98	332.05	39.02
MGS Unit 2 Steam Boiler – to be removed	0	0	0	0	0	0
MGS Unit 3 CTG	0.75	45.64	2.01	0.06	11.41	0
MGS 154 BHP Emergency Engine–to be removed	0	0	0	0	0	0
MGS 201 BHP Emergency Engine–to be removed	0	0	0	0	0	0
P3 New 262 MW Turbine	10.84	32.95	10.68	5.91	54.42	17.62
P3 New 779 BHP Engine	0.01	0.02	0.00	0.00	0.11	0
Post-Project Total Stationary Source	23.22	167.10	33.45	10.95	397.99	56.64
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As seen in Table VII-14 above, post project the facility is a major source for NOx only.

Rule 26.6 C – Actual Emissions:

The new CTG and new IC engine have no actual existing emissions as defined by Rule 26.6.C.

The actual emissions from the existing natural gas fired electrical steam boilers (MGS Unit 1 and Unit 2) and existing natural gas-fired peaker CTG (MGS Unit 3) are calculated from the permitted emission factors and their historical fuel use (see Tables VII-15 and VII-16). The NOx emissions for MGS Unit 1 and MGS Unit 2 are based on the NOx CEMs data from the facility. The emission factors are shown in Tables VII-15 and VII-16 below. The historical fuel use was determined from fuel records from the baseline period (2012-2013). Based on Rule 26.6.C, this two consecutive year period was determined to be the most representative as it best reflects current electricity market. The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 15

Actual Emissions for Existing Natural Gas Fired Steam Boiler - MGS Unit 1			
Pollutant	Emission factor (lb/MMscf)	Avg. Annual Fuel Use (MMscf)	Tons Per Year
ROC	1.40	1,101.70	0.77
NOx	3.42	1,101.70	1.88
PM ₁₀	2.50	1,101.70	1.38
SOx	0.60	1,101.70	0.33
CO	40.0	1,101.70	22.03

Table VII - 16

Actual Emissions for Existing Natural Gas Fired Steam Boiler – MGS Unit 2			
Pollutant	Emission factor (lb/MMscf)	Avg. Annual Fuel Use (MMscf)	Tons Per Year
ROC	1.40	1,297.75	0.91
NOx	4.68	1,297.75	3.04
PM ₁₀	2.50	1,297.75	1.62
SOx	0.60	1,297.75	0.39
CO	40.0	1,297.75	25.96

The actual emissions from the existing natural gas fired CTG (MGS Unit 3) are calculated from the emission factors and its historical fuel use (see Table VII-17). The historical fuel

use was determined from fuel records from the baseline period (2012-2013). The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 17

Actual Emissions for Existing Natural Gas Fired Turbine – MGS Unit 3			
Pollutant	Emission factor (lb/MMscf)	Avg. Annual Fuel Use (MMscf)	Tons Per Year
ROC	7.56	88.55	0.33
NO _x	462.0	88.55	20.46
PM ₁₀	20.30	88.55	0.90
SO _x	0.60	88.55	0.03
CO	115.50	88.55	5.11

The actual emissions from the existing emergency engines are calculated from the emission factors and their historical fuel use (see Tables VII-18 and VII-19. The historical fuel use was determined from fuel records from the baseline period (2012-2013). The fuel records are attached in Appendix D – Historical Fuel Records.

Table VII - 18

Actual Emissions for Existing 154 BHP Emergency Engine		
Pollutant	Pounds Per Hour	Tons Per Year
ROC	0.04	0.00
NO _x	0.51	0.00
PM ₁₀	0.04	0.00
SO _x	0.01	0.00
CO	0.11	0.00

Table VII - 19

Actual Emissions for Existing 201 BHP Emergency Engine		
Pollutant	Pounds Per Hour	Tons Per Year
ROC	0.05	0.00
NO _x	0.67	0.00
PM ₁₀	0.05	0.00
SO _x	0.01	0.00
CO	0.15	0.00

As shown above, the two existing emergency diesel engines have no actual existing emissions in the units of tons per year.

Rule 26.6 D – Emission Increases:

Rule 26.1.18 defines a major source as “A stationary source which emits or has the potential emit 25 tons per year or more of nitrogen oxides (NO_x) or reactive organic compounds (ROC).” There are not major source thresholds for PM₁₀, SO_x, or CO.

As shown above the facility is currently a major source of NO_x and will remain a major source of NO_x after the installation of the new CTG and emergency IC engine. The facility is not currently a major source of ROC, and will not become a major source of ROC.

Rule 26.1.29 defines Replacement Emissions Unit as “An emissions unit which supplants another emissions unit where the replacement emissions unit serves the identical function as the emission unit being replaced.” The new 262 MW gas turbine will be connected to the same Southern California Edison 220-KV switchyard that the two (2) existing 215 MW Babcock and Wilcox Steam Generator boilers (MGS Units 1 and 2) are connected to. Once operating, the new 262 MW gas turbine will provide dispatchable power to provide voltage support to the local reliability area in the same manner as the current two 215 MW Babcock and Wilcox Steam Generators. Once the commissioning activities for the new CTG are completed, MGS Unit 2 will be permanently shut down. Therefore the new turbine is a replacement emissions unit for MGS Unit 2. As described above, eventually MGS Unit 1 will also be permanently shut down and the new CTG will serve as a replacement for both MGS Unit 1 and MGS Unit 2..

Additionally, the new 779 BHP emergency diesel generator is replacing two existing emergency diesel engines, one for an electrical generator and one for a fire water pump. The new engine is providing emergency backup power in the same manner as the existing engine. Therefore the new emergency diesel engine is a replacement emissions unit for the two existing emergency IC engines.

Pursuant to Rule 26.6.D.2, an emissions increase for a replacement project is calculated as the emissions unit’s post-project potential to emit adjusted to reflect current BACT minus the emissions unit’s pre-project potential to emit adjusted to reflect current BACT. However, pursuant to Rule 26.6.D.7 this potential-to-potential emission calculation does not apply to a major modification of ROC or NO_x.

Therefore, the emissions increase for this project will be calculated on a potential-to-potential basis for ROC, PM₁₀, and SO_x. The emissions increase for NO_x will be calculated on an actual-to-potential basis. Note that Rule 26.2 does not require emission offsets for CO or NH₃.

For a major modification of ROC or NO_x as defined in Rule 26.1.19, pursuant to Rule 26.6.D.7, an emissions increase is calculated as the post-project potential to emit minus the emissions unit’s pre-project actual emissions. Actual emissions are defined in Rule 26.6.C and are based on an average of the most recent two years of operation, or as determined by the APCO, a more representative period of two consecutive years in the most recent five years of operation. The facility is a major source for NO_x but not for ROC. Therefore, the project cannot be a major modification for ROC.

Therefore, the NOx emissions increase will be calculated based the post-project potential to emit minus the emissions unit's pre-project actual emissions. The NOx emission calculations are shown in the Table VII-20 below:

Table VII - 20

Actual to Potential NOx Emission Changes (Rule 26.6.D.7)	NOx Tons Per Year
New P3 262 MW Turbine Emissions – potential emissions	+32.95
New P3 779 BHP Engine Emissions – potential emissions	+0.02
Remove existing MGS Unit 2 – actual emissions	-3.04
Remove Existing MGS 154 BHP Engine - actual emissions	-0.00
Remove Existing MGS 201 BHP Engine - actual emissions	-0.00
NOx Emission Change	+29.93

As shown in Table VII-20 above, the NOx emission increase is greater than the Rule 26.1.19 definition of major modification threshold of 25 tons per year. Therefore the project is a major modification for NOx.

The emission change for ROC will be calculated based on the potential emissions, as the facility is not a major source for ROC. PM10 and SOx will be calculated based on the potential emissions both pre-project and post-project as these pollutants do not have major source thresholds. The ROC, PM10, SOx, and CO emission change calculations are shown in Table VII-21 below.

Table VII - 21

Potential to Potential Emission Changes (Rule 26.6.D.2)	Tons Per Year			
	ROC	PM₁₀	SOx	CO
New P3 262 MW Turbine - potential emissions	10.84	10.68	5.91	54.42
New P3 779 BHP Emergency Engine - potential emissions	0.01	0.00	0.00	0.11
Remove Existing MGS Unit 2 - potential emissions	-11.62	-20.75	-4.98	-332.04
Remove existing 154 BHP Emergency Engine - potential emissions	0.00	0.00	0.00	-0.01
Remove existing 201 BHP emergency engine - potential emissions	0.00	0.00	0.00	-0.01
Emission Change	-0.77	-10.07	+0.93	-277.53

VIII. Analysis of Compliance With Applicable Rules and Regulations

Rule 26.2 – Section A Best Available Control Technology

Rule 26.2.A requires any application for new, replacement, modified, or relocated emissions units which have a potential to emit of any of the pollutants listed in Table 1 of Rule 26.2 shall install Best Available Control Technology for such pollutant. This rule and Table 1 have a zero threshold for BACT for ROC, NO_x, PM-10, and SO_x. BACT is not required for CO.

1. 262 MW Nominal Combustion Gas Turbine:

BACT requirements apply for ROC, NO_x, PM-10, and SO_x. The unit is a simple cycle cogeneration turbine, meaning it employs a “simple power cycle” and no secondary steam is produced. There is no heat recovery steam generator (HRSG). BACT databases for other air districts yield the following information:

US EPA RACT/BACT/LAER Clearinghouse: The US EPA has a collection of RACT/BACT/LAER determination guidelines for facilities from across the nation. A search of the database for simple cycle turbines over 25 MW showed the following recent BACT determinations (see Table VII-22).

Table VII - 22

EPA RACT/BACT/LAER Natural Gas Simple Cycle Turbine > 25MW				
Date	Facility	NO_x	ROC	PM
10/14/15	Nacogdoches Power, LLC (232 MW turbine)	9.0 ppmvd @15% O ₂	2.0 ppmvd @15% O ₂	12.09 lb/Hr
10/27/15	Van Alstyne Energy Center (183 MW turbine)	9.0 ppmvd @15% O ₂	None	8.6 lb/Hr

SCAQMD: The South Coast Air Quality Management District (SCAQMD) separates out their BACT guidelines for major and non-major polluting facilities. Major source facilities BACT guidelines are evaluated on a case by case basis. The recent non-major guidelines have been reviewed as well. The non-major guidelines for gas turbines do not make any distinctions based on the type of turbine; however, there are distinctions for turbine size. The SCAQMD Non-Major BACT emission levels for >50MW gas turbine is shown in Table VII-23 below:

Table VII - 23

SCAQMD BACT >50 MW Turbine			
Date	SCAQMD Gas Turbine	NOx	ROC
10/20/00	Natural Gas Fired, > 50 MW	2.5 ppmvd @ 15% O ₂ , 1 Hr rolling avg. OR 2.0 ppmvd @ 15% O ₂ , 3 Hr rolling avg. x efficiency (%)	2.0 ppmvd as methane @ 15% oxygen, 1 Hr avg. OR 0.0027 lb/MMBTU (HHV)

The SCAQMD provides the following site-specific BACT determinations in its major source BACT section for simple cycle turbines (see Table VII-24):

Table VII - 24

SCAQMD Site Specific Determinations					
Date	Project Location	Equipment	NOx limit	ROC limit	Comments
02/10/04	EI Colton, LLC Colton, CA	1 – 48.7 MW GE LM6000	3.5 ppmvd (3-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Hi temp SCR/oxidation catalyst
12/18/01	Indigo Energy Facility / Palm Springs, CA	3 – 45 MW GE LM 6000	5 ppmvd (1-Hr avg.)	2 ppmvd (1-Hr avg.)	High temp SCR/oxidation catalyst

SJVAPCD: The San Joaquin Valley Air Pollution Control District (SJVAPCD) does not separate gas turbines by simple cycle or combined cycle. Instead they categorize the turbines either as with or without heat recovery. The BACT SJVAPCD Guidelines for turbines = or > 50 MW, Uniform Load, without heat recovery are shown in Table VII-25:

Table VII - 25

SJVAPCD BACT Guideline 3.4.7			
Date	SJVAPCD Gas Turbine	NOx	ROC
10/01/02	= or >50 MW, Uniform Load, without Heat Recovery	<u>Achieved in practice:</u> 5.0 ppmvd @15% O ₂ , 3 Hr avg. (high temp SCR) <u>Technologically feasible:</u> 2.5 ppmvd @ 15% O ₂ (high temp SCR or equal) 3.0 ppmvd @ 15% O ₂ (high temp SCR or equal)	<u>Achieved in practice:</u> 2.0 ppmvd @15% O ₂ , 3 Hr avg. (oxidation catalyst) <u>Technologically feasible:</u> 0.6 ppmvd @15% O ₂ , 3 Hr avg. (oxidation catalyst) 1.3 ppmvd @15% O ₂ , 3 Hr avg. (oxidation catalyst)

SJVAPCD provides the following site-specific BACT determination shown in Table VII-26:

Table VII - 26

SJVAPCD Site Specific BACT Determination					
Date	Project/Location	Equipment	NOx limit	ROC limit	Comments
10/05/01	GWF Energy Tracy, CA	84.4 MW GE PG7121, Turbine	5.0 ppmvd (3-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Dry low NOx combustors SCR/oxidation catalyst

BAAQMD: The Bay Area Air Quality Management District determines BACT requirements on a case by case basis. The latest BACT determination for a turbine was done in July 2003. The resulting BACT database includes the information in Table VII-27 below:

Table VII - 27

BAAQMD Simple Cycle >= 40 MW BACT Determination 89.1.3			
Date	BAAQMD Gas Turbine	NOx	ROC
07/18/03	≥ 40 MW, simple cycle	2.5 ppmvd @ 15% O2 (Hi temp SCR+ water or steam injection)	2.0 ppmvd @ 15% O2 (oxidation catalyst)

CARB Guidance: California Air Resource Board BACT Clearinghouse does not have an entry for a Gas Turbine Simple Cycle > 50 MW. However, for smaller simple-cycle turbines the following guidance is presented in Table VII-28:

Table VII - 28

CARB BACT Simple Cycle >2MW <50 MW			
Date	CARB Guidance	NOx	ROC
09/2001	> 12 and < 50 MW	2.5 ppmvd @15% O2	2.0 ppmv @ 15% O2

BACT Discussion:

As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.5 ppmvd NOx @ 15% O2 and 2.0 ppmvd ROC @ 15% O2 have been achieved in practice for a simple cycle turbine. These levels have been achieved using an SCR system for NOx control and an oxidation catalyst. No lower emission levels for NOx and ROC have been identified as being technologically feasible.

These emission levels and controls have been proposed by the applicant to satisfy BACT.

BACT for PM10 and SOx will be the use of PUC regulated natural gas. This is accepted achieved-in-practice BACT by the SCAQMD, SJVAPCD, and BAAQMD BACT Guidelines. No lower emission levels for PM10 and SOx have been identified as being technologically feasible.

Therefore, BACT for the Puente Power Project GE 7HA.01 Gas Turbine is as follows in Table VII-29:

Table VII - 29

BACT Gas Turbine	
NOx	2.5 ppmvd @ 15% O ₂ , 1 Hr average, SCR
ROC	2.0 ppmvd @ 15% O ₂ as methane, 1 Hr average
PM ₁₀	PUC regulated natural gas only
SOx	PUC regulated natural gas only

2. 779 BHP Emergency Diesel Engine:

BACT requirements apply for ROC, NOx, PM-10, and SOx. The unit is a 779 diesel fired emergency engine. The engine has a 50 hours per year limit for non-emergency operation. The applicant has proposed a diesel engine that meets US EPA non-road Tier 4 final standards. BACT databases for other air districts yield the following information:

SCAQMD:

The SCAQMD BACT manual lists BACT AN:392542 for 764 BHP Emergency IC engine, compression ignition, as the engine meets the applicable US EPA non-road Tier engine standard. The engine is required to use fuel with sulfur content of <0.05%.

SJVAPCD:

The SJVAPCD BACT lists BACT 3.1.1 for emergency diesel IC engines as the engine meets the latest US EPA Tier certification for NOx, ROC. Very low sulfur diesel fuel (15 ppmw sulfur or less). PM10 emissions of 0.15 g/BHP-Hr or the latest US EPA Tier Certification, whichever is more stringent.

BAAQMD:

The BAAQMD BACT lists BACT 96.1.3 for IC engine, compression ignition, stationary emergency as the engine meets CARB ATCM standard for ROC and NOx. Very low sulfur diesel fuel (15 ppmw sulfur or less). PM10 emissions of 0.15 g/BHP-Hr.

No lower emission levels for NOx, ROC, PM10, or SOx have been identified as being technologically feasible.

BACT for the Emergency IC engine is presented in Table VII-30 below:

Table VII - 30

BACT Emergency IC Engine	
NO _x	US EPA non-road Tier 4 final standard
ROC	US EPA non-road Tier 4 final standard
PM ₁₀	US EPA non-road Tier 4 final standard
SO _x	Very low sulfur diesel fuel (15 ppmw sulfur or less)

Rule 26.2 – New Source Review Requirements, Section B – Offsets

Rule 26.2.B details the emission offset requirements for new, replacement, modified, or relocated emissions units. There are only offset requirements for ROC, NO_x, PM₁₀, and SO_x. Emission offsets are not required for CO or NH₃.

The offset thresholds are shown in Rule 26.2.B.1 Table B-1 (Table VII-31 below):

Table VII-31

Rule 26.2.B Table B-1 Offset Thresholds			
Pollutant	Offset Threshold	Facility Post-Project Emissions	Offsets Review Triggered?
ROC	5.0 ton/yr	23.22 ton/yr	Yes
NO _x	5.0 ton/yr	167.10 ton/yr	Yes
PM ₁₀	15.0 ton/yr	33.45 ton/yr	Yes
SO _x	15.0 ton/yr	10.95 ton/yr	No

As shown in the table above, the offset thresholds of Rule 26.2 Table B-1 are exceeded for ROC, NO_x and PM₁₀. Therefore, offsets will be required for any emission increases in ROC, NO_x, and PM₁₀ as calculated pursuant to Rule 26.6, New Source Review - Calculations. There are no offsets required for any SO_x emission increases as the offset threshold will not be exceeded.

NO_x Offset Requirements – Actual to Potential Emission Increases (Rule 26.6.D.7)

The increase in NO_x emissions from the proposed CTG and IC engine will be offset using Emission Reduction Credits (ERCs). The NRG MGS facility is a major source for NO_x. Please note that NO_x emissions offsets were not provided for the existing boilers (MGS Units 1 and 2) or the existing emergency engines when they were originally placed into service. Therefore, per Rule 26.6 Section D.7.a, the NO_x emissions increase is equal to the post-project potential to emit minus the pre-project actual emissions.

The facility will be required to provide NOx offsets at a tradeoff ratio of 1.3 to 1 as per Rule 26.2.B.2.a. The quantity of offsets required is shown below.

NOx offsets required = increase in NOx emissions x 1.3 offset ratio

$$\begin{aligned} &= (\text{new CTG replacing MGS Unit 2} + \\ &\quad \text{new IC engine replacing two existing IC engines}) \times 1.3 \text{ offset ratio} \\ &= (32.95 \text{ tons} - 3.04 \text{ tons} + 0.02 \text{ tons} - 0.00 \text{ tons}) \times 1.3 \text{ offset ratio} \\ &= 29.93 \text{ tons NOx/yr} \times 1.3 \text{ offset ratio} \\ &= 38.91 \text{ tons NOx/yr} \end{aligned}$$

The District has determined that the following NOx ERC Certificates proposed by the applicant are eligible for use as emission offsets for the Puente Power Project. NOx offsets will be provided from ERC Certificate Nos. 1078, 1079, 1080, 1083, 1085, 1091, 1092, 1094, 1097, 1104, and 1107 owned by the Southern California Edison Co. These ERC Certificates currently have a total NOx balance of 50.66 tons per year. Pursuant to Rule 26.4.D.3, there are no limitations on the use of these emission reduction credits and they may be used as proposed for the Puente Power Project. A digital copy of each of these ERC Certificates is included in Appendix E – ERCs Identified For Possible Use.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these NOx offsets are not required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program shows a positive balance for NOx.

All of these ERC Certificates were created by the Southern California Edison Co. in the early 1990's as a part of an electrification conversion program. Over eighty (80) natural gas-fired engines were replaced with electric motors. These engines were used to power equipment such as oil well rod pumping units, natural gas compressors, and water well pumps. These ERC Certificates have all been assigned a quarterly profile of 25%, 25%, 25%, 25%.

ROC Offset Requirements - Potential to Potential Emission Increases (Rule 26.6.D.2):

The NRG Mandalay Generating Station is not a major source for ROC.

The facility will be required to provide ROC offsets at a tradeoff ratio of 1.1 to 1 as per Rule 26.2.B.2.b.1 for any emission increase. The quantity of offsets required is shown below.

ROC offsets required = increase in ROC emissions x 1.1 offset ratio

$$\begin{aligned} &= (\text{new CTG replacing MGS Unit 2} + \\ &\quad \text{new IC engine replacing two existing IC engines}) \\ &= (10.84 - 11.62) \text{ tons} + (0.01 - 0.00 - 0.00) \text{ tons} \\ &= -0.77 \text{ tons ROC/yr} \end{aligned}$$

As shown above there is no increase in ROC emissions. Therefore, offsets are not required for ROC.

PM10 Offset Requirements - Potential to Potential Emission Changes (Rule 26.6.D.2):

The NRG Mandalay Generating Station is not a major source for PM10.

The facility will be required to provide PM10 offsets at a tradeoff ratio of 1.1 to 1 as per Rule 26.2.B.2.c for any emission increase. The quantity of offsets required is shown below.

PM10 offsets required = increase in PM10 emissions

$$\begin{aligned} &= (\text{new CTG replacing MGS Unit 2} + \\ &\quad \text{new IC engine replacing two existing IC engines}) \\ &= (10.68 - 20.75) \text{ tons} + (0.00 - 0.00 - 0.00) \text{ tons} \\ &= -10.07 \text{ tons PM10/yr} \end{aligned}$$

As shown above there is no increase in PM10 emissions. Therefore, offsets are not required for PM10.

Rule 26.2 B. 4 Offsets - ERC Quarterly Profile Check

As discussed above, the ERC Certificates that will be used for the Puente Power Project have all been assigned a quarterly profile of 25%, 25%, 25%, 25%. These proposed ERC Certificates are expected to meet the quarterly profile check of Rule 26.2.B.4 and Rule 26.6.F as shown in Appendix F – ERC Profile Check. Rule 26.6.F requires the profile check be equal to at least 80 percent. In a March 29, 2016 letter, the applicant has stated that the Puente Power Project is expected to operate in a manner similar to Mandalay Generating Station Unit Nos. 1 and 2 for the most recent calendar years 2013, 2014, and 2015. In this letter, these years meet the quarterly profile check of 80 percent based on a 3-year average gross electrical output (MW-Hr) combined for MGS Unit Nos. 1 and 2. In addition, Appendix F shows that the average quarterly profile for MGS Unit Nos. 1 and 2 combined at the Mandalay Generating Station for the years 2010, 2011, 2012, 2013, and 2014 also meet the quarterly profile check of 80% based on the actual natural gas consumption records.

Rule 26.2 Section C - Protection of Ambient Air Quality Standards and Ambient Air Increments

Rule 26.2.C requires the denial of any application for any new, replacement, modified, or relocated emissions unit that would cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR Part 51.166(c). Modeling of the Puente Power Project indicates that the project will not cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR Part 51.166(c). See Appendix G.

Rule 26.2 Section D - Certification of Statewide Compliance

The applicant must certify that all major sources, as defined in their specific nonattainment area, that are both located in California and owned or operated by the applicant, or by any entity controlling, controlled by or under common control with such applicant, are in compliance or on a schedule for compliance with all applicable emission limitations and

standards. The applicant has provided a Certification of Statewide Compliance. See Appendix I.

Rule 26.2 Section E - Analysis of Alternatives

The applicant must provide an analysis of alternatives as required by Section 173(a)(5) of the federal Clean Air Act, of alternative sites, sizes, production processes, and environmental control techniques for the proposed source demonstrating that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification. The applicant has provided an analysis of alternatives. See Appendix J.

Rule 26.7 New Source Review – Notification

This Rule specifies the cases in which notification shall be provided of the Air Pollution Control Officer's preliminary decision to grant an Authority to Construct, or issue a Certificate of Emission Reduction Credit. In addition, this Rule specifies the process by which such notification shall be made. The power plant project will result in an increase in NOx emissions over the 15.0 tons per year threshold and therefore a notification period will occur. The notification shall be published in a newspaper of general circulation in Ventura County in both English and Spanish. The notice period shall provide 30 days for the public to submit written comments regarding the decision. The District shall consider all comments made during the comment period.

The District shall also submit a copy of the notice and supporting data and analysis to the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA) for comments.

The District will provide written notification to any person or agency which submitted comments during the comment period.

Rule 26.9 New Source Review - Power Plants

This rule applies to the Puente Power Project as an Application for Certification has been submitted to the California Energy Commission (Docket No. 15-AFC-01). The District conducted a Determination of Compliance review (this document) as required by Rule 26.9. Compliance with this rule is confirmed.

Rule 26.11 New Source Review – ERC Evaluation at Time of Use

This rule provides for the evaluation by the District of emission reduction credits for reactive organic compounds (ROC) and nitrogen oxides (NOx) at the time that the Authority to Construct (in this case a Determination of Compliance) is issued. As the Puente Power Project is required to provide NOx offsets as calculated above, the District shall evaluate the proposed offsets per Rule 26.11 Section B.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these NOx offsets are not required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program shows a positive balance for NOx.

Rule 26.12 New Source Review – Federal Major Modifications

As shown in the Rule 26.6.D emission increase calculations, the Puente Power Project results in a major modification for NO_x only. Major modifications are also federal major modifications unless there is a less than significant emissions increase or no increase in an existing plant-wide applicability limit.

This project results in a significant emissions increase for NO_x. Additionally the facility does not have an existing plant-wide applicability limit. Therefore, this project is a federal major modification for NO_x. As such the facility must comply with the requirements of Rule 26.2.E – Analysis of Alternatives. See the Rule 26.2.E compliance section above and Appendix J.

Rule 29 Conditions On Permits

Section A of this rule requires the District to apply conditions to permits which are necessary to assure that a stationary source and all emissions units at the stationary source will operate in compliance with applicable state and federal emission standards and with Ventura County APCD Rules, including permit conditions required by Rule 26, New Source Review.

Section B of this rule requires the District to apply conditions to permits which will limit the amount of air contaminants a stationary source may emit. These emission limits are called permitted emissions and shall be expressed in pounds per hour and tons per year. In addition, conditions may include restrictions on production rates, fuel use rates, raw material use rates, hours of operation or other reasonable conditions to insure that the permitted emission limits are not exceeded.

This DOC contains conditions that both assure compliance with all applicable federal, state and Ventura County APCD rules and limit the stationary source permitted emissions in the units of tons per year and pounds per hour.

Rule 33.5 Part 70 Permits – Timeframes for Applications, Review and Issuance

Facilities that are subject to the requirements of Part 70 permits (commonly called Title V sources) must submit timely applications to revise their Part 70 permit. The Puente Power Project is a significant modification to the existing Title V permit for the Mandalay Generating Station. Therefore, NRG will be required to submit a Part 70 application to the District prior to operating such source pursuant to the modification. A condition has been placed on the DOC to ensure the facility submits a Part 70 modification application prior to operation of the new equipment.

Rule 34 Acid Deposition Control

A Title IV Acid Rain permit is required for the proposed turbine because the unit is a new fossil fuel fired combustion device used to generate electricity for sale with an electrical output of greater than 25 MW. The Title IV Acid Rain permit is required pursuant to 40 CFR Part 72, which is incorporated into VCAPCD rules by District Rule 34, Acid Deposition

Control. The Determination of Compliance will require that NRG submit the Title IV Acid Rain permit application prior to operating the new turbine.

Rule 50 Opacity

Rule 50 limits visible emissions to an opacity of less than 20 percent (Ringelmann No. 1), as published by the United States Bureau of Mines. Visible emissions are not expected under normal operation from the turbine, emergency diesel engine, or ammonia tank.

Rule 51 Nuisance

Rule 51 requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new equipment, including the turbine, engine, and ammonia tank, are not expected to create nuisance problems, such as smoke or odors.

The District has conducted a risk management review (RMR) under the Ventura County APCD Policy "Air Toxics Review of Permit Applications" dated July 10, 2002. The review can be found in Appendix G. The calculated maximum risks are below:

RMR Results

Unit Description	Cancer Risk	Hazard Index		Health Risk Reduction Plan Required?
		Chronic	Acute	
Using Adjusted U* Option (Adj-U*)				
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	2.08 x 10 ⁻²	No
Diesel Emergency Engine	5.37 x 10 ⁻⁸	1.66 x 10 ⁻⁵	---	No
Project Total	8.48 x 10 ⁻⁸	9.23 x 10 ⁻⁵	2.08 x 10 ⁻²	No
Not Using Adjusted U* Option				
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	4.19 x 10 ⁻²	No
Diesel Emergency Engine	4.22 x 10 ⁻⁸	1.59 x 10 ⁻⁵	--	No
Project Total	7.32 x 10 ⁻⁸	9.12 x 10 ⁻⁵	4.19 x 10 ⁻²	No

These risks are well below the District's "no further action" thresholds of 1 in a million for excess cancer risk, 0.5 for the chronic hazard index, and 0.5 for the acute hazard index. Therefore, compliance with Rule 51 is expected.

Rule 54 Sulfur Compounds

Rule 54 requires compliance with sulfur dioxide (SO₂) emission limits of 300 ppmv and compliance with ground level concentration limits of SO₂ (0.25 ppmv averaged over 1 hour, 0.04 ppmv averaged over 24 hours, and 0.075 ppmv 1-hour average design value). The combustion of PUC natural gas only results in compliance with the 300 ppmv emission limit. Emissions from the project result in maximum modeled ground level concentrations

of $1.3 \mu\text{g}/\text{m}^3$ (0.0004 ppmv) on a 1 hour average and $0.2 \mu\text{g}/\text{m}^3$ (0.00008 ppmv) on a 24 hour average. These concentrations are below the limits of Rule 54. See the air dispersion modeling results in Appendix G.

Rule 55 Fugitive Dust

The provisions of this rule shall apply to any operation, disturbed surface area, or man-made condition capable of generating fugitive dust, including bulk material handling, earth-moving, construction, demolition, storage piles, unpaved roads, track-out, or off-field agricultural operations. This rule places limits on visible dust, opacity, and track out from activities subject to the rule.

The applicant has proposed mitigation measures during the construction phase of Puente Power Project that will assure compliance with this rule. Compliance with this rule is expected during the routine operation of the Puente Power Project.

Rule 57.1 Particulate Matter Emissions From Fuel Burning Equipment

The rule requires that particulate matter emissions from the turbine not exceed 0.12 pounds per million BTU of fuel input. At the manufacturer's guaranteed particulate matter emission rate of 10.1 pounds per hour (which is greater than the EPA AP-42 emission factor) and the maximum fuel input rate of 2,572 MMBTU/Hr, the particulate matter emissions are 0.004 lb per MMBTU, which is significantly less than the Rule 57.1.B limit of 0.12 lb per MMBTU. Therefore compliance with the rule is expected.

Rule 57.1 does not apply to internal combustion engines, pursuant to Section C.1 of the rule. Therefore, the rule does not apply to the new emergency engine.

Rule 64 Sulfur Content of Fuels

Rule 64.B.1 prohibits the combustion of gaseous fuels that contain sulfur compounds in excess of 50 grains per 100 cubic feet (788 ppmv), calculated as hydrogen sulfide at standard conditions. The turbine will be required to burn only Public Utilities Commission (PUC) regulated natural gas which meets this requirement. Rule 64.B.2 prohibits the combustion of liquid fuels that have a sulfur content in excess of 0.5 percent by weight. The emergency engine will only use ARB-certified diesel fuel that meets this limit. Section C.2 of the rule states that the monitoring and recordkeeping sections of the rule do not apply when PUC-regulated natural gas is or ARB-certified diesel is used. Therefore compliance with this rule is expected.

Rule 74.9, Stationary Internal Combustion Engines

The facility is installing a 779 BHP Caterpillar emergency diesel fired internal combustion engine. The engine will provide emergency power when there is a grid electricity power failure. The facility has indicated that it will be operated less than or equal to 50 hours per year for non-emergency use such as engine maintenance and readiness testing. Pursuant to Section D.3 of Rule 74.9, the engine is exempt from the Section B (Requirements), Section C (Engine Operator Inspection Plan), and Section E (Recordkeeping) requirements of Rule 74.9 because it will be operated less than 50 hours per calendar year

for non-emergency use. A non-resettable elapsed hour meter is required by Rule 74.9.D.3. The facility will submit the engine annual operating hours to the District per Rule 74.9.F.2.

Rule 74.23 Stationary Gas Turbines

The proposed GE 7HA.01 gas turbine is subject to the $9 \times E/25$ ppmvd @ 15% oxygen NO_x limit of Rule 74.23.B.1. (E is the Unit Efficiency Percent and is not less than 25 percent as defined in the rule.) The NO_x BACT limit of 2.5 ppmvd @ 15% oxygen is more stringent than the Rule 74.23 limit as described above. Rule 74.23 requires an annual source test to verify compliance with the NO_x limit. The required NO_x continuous emission monitor will also verify compliance with the NO_x emission limit.

The turbine is also subject to the 20 ppmvd ammonia (NH₃) limit of Rule 74.23.B.4. The proposed ammonia limit of 5 ppmvd @ 15% oxygen is more stringent than the Rule 74.23 limit. Compliance with this ammonia limit will be verified by an annual source test.

Section C.1.e of Rule 74.23 exempts the turbine from the NO_x and NH₃ emission concentration limits during start-up, planned shutdown, and unplanned load change periods. These exemption periods shall not exceed one (1) hour. For failed start-ups, each restart shall begin a new exemption period. The proposed conditions include limits on the durations of startup and shutdown consistent with these time periods.

Section D.1 requires records to be kept and available upon request for District inspection for 2 years. However, District Rule 103, Continuous Monitoring Systems, requires records to be kept for 5 years. The facility will be required to keep records for 5 years.

Section E requires the facility to provide the District with reports and data identifying the annual usage (e.g., fuel consumptions, operating hours, etc.) of the turbine and the annual compliance verification source test.

Section F identifies specific test methods to be used to verify compliance. The facility will use these test methods for compliance.

Rule 103 Continuous Monitoring Systems

The application proposes that the new GE 7HA.01 Turbine be equipped with NO_x, CO, and O₂ Continuous Emission Monitors (CEMs). Such CEMs will be required pursuant to Rule 103.A.1 for sources subject to federal regulations that require CEMs. The Determination of Compliance will require that the CEM system be operated in compliance with Rule 103. The requirements of Rule 103 include the installation, calibration, and maintenance of the system in accordance with the specifications for electric power generating units in 40 CFR, Part 75, Continuous Emission Monitoring, Subpart C, Operation and Maintenance Requirements, which includes by reference Appendix A to Part 75, Specifications and Test Procedures, and Appendix B to Part 75, Quality Assurance and Quality Control Procedures. Note that a CEMS is also required by 40 CFR Part 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines" as discussed below.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that the new CTG and the emergency engine are not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The proposed emergency engine is subject to this ATCM. The engine will be restricted to emergency usage and 50 hours per year for maintenance and testing purposes. The following requirements will apply to the new engine.

Title 17 CCR Section 93115 Requirements for New Emergency IC Engines Powering Electrical Generators	Proposed Method of Compliance with Title 17 CCR Section 93115 Requirements
Emergency engine(s) must be fired on CARB diesel fuel, or an approved alternative diesel fuel.	The applicant has proposed the use of CARB certified diesel fuel. The proposed permit condition, requiring the use of CARB certified diesel fuel, was included earlier in this evaluation.
The engine(s) must meet the emission standards in Table 1 of the ATCM for the specific power rating and model year of the proposed engine.	The applicant has proposed the use of engine that is certified to the latest EPA Tier Certification standards for the applicable horsepower range, guaranteeing compliance with the emission standards of the ATCM. Additionally, the proposed diesel PM emissions rate is less than or equal to 0.15 g/BHP-Hr.
The engine may not be operated more than 50 hours per year for maintenance and testing purposes.	The following condition will be included on the permit: • <i>This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.</i>

A non-resettable hour meter with a minimum display capability of 9,999 hours shall be installed upon engine installation, or by no later than January 1, 2005, on all engines subject to all or part of the requirements of sections 93115.6, 93115.7, or 93115.8(a) unless the District determines on a case-by-case basis that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.	The following condition will be included on the permit: <i>This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.</i>
An owner or operator shall maintain monthly records of the following: emergency use hours of operation; maintenance and testing hours of operation; hours of operation for emission testing; initial start-up testing hours; hours of operation for all other uses; and the type of fuel used. All records shall be retained for a minimum of 36 months.	Permit conditions enforcing these requirements were shown earlier in the evaluation.

Public Resources Code 21000-21177 - California Environmental Quality Act (CEQA) - California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387 CEQA Guidelines

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The California Energy Commission (CEC) has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(k)), it is functionally equivalent to CEQA.

The District holds no discretionary approval powers over this project; however the District prepares a Determination of Compliance (DOC), this document as required by Rule 26.9, New Source Review - Power Plants. The DOC confers the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this DOC (20 CCR § 1744.5 and Rule 26.9). A Permit to Operate is required to be issued if the project receives a certificate from the CEC and the project is constructed in accordance with the conditions set forth in the DOC (Rule 26.9).

The District makes the following findings regarding this project: the District holds no discretionary approval powers over this project and the District's actions are ministerial (CEQA Guidelines § 15369).

District Rule 13 Section C.2 requires for projects requiring CEQA review for the District to issue or deny an Authority to Construct (or in this case a DOC) within 180 days of the date the lead agency has approved the project. Since the DOC will be issued as a part of the lead agency's approval of the project (i.e. the CEC's issuance of a certificate), compliance with this requirement is confirmed.

40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines"

The proposed 779 BHP Caterpillar emergency diesel fired engine is subject to the Compression Ignition Internal Combustion Engine NSPS (Subpart IIII).

Sections 60.4201 through 60.4203 apply to engine manufacturers only. Section 60.4204 contains standards for non-emergency engines that do not apply to this engine since it is an emergency engine.

Section 60.4205 contains emission standards for the engine. The emergency engine is required to comply with the emission standards for non-road compression ignition engines in 40 CFR 89.112 and 89.113. For engines in this power range and model year, these standards require the engine be certified to standards of 4.0, 3.5 and 0.20 g/kW-Hr (3.0, 2.6, 0.15 g/BHP-hr) for NMHC+NO_x, CO and PM respectively, which are known as "Tier 3" standards. The proposed engine is a "Tier 4" certified engine with emission levels below these values, therefore the engine meets this requirement.

Section 60.4207 requires the use of low sulfur fuel. Proposed permit conditions require CARB diesel fuel, which satisfies the low sulfur fuel requirement.

Section 60.4209 requires that emergency engine be equipped with a non-resettable hour meter. Proposed permit conditions will require an hour meter which satisfies the requirement.

Section 60.4211 requires that the engine be certified and be operated and maintained according to the manufacturer's emission-related written instructions. The engine is an emergency engine under this rule, so is restricted to operating in certain scenarios. The engine may be operated for unlimited duration in emergency situations. Maintenance and testing is limited to up to 50 hours per year. Proposed permit conditions allow the emergency engine to operate in emergency situations and for up to 50 hours per year for maintenance and testing operations.

Section 60.4214 requires that the owner or operator maintain logs of engine operation including durations and reason for use. This requirement is specified in proposed permit conditions. No notifications or reports are required. The proposed permit conditions contain requirements to ensure compliance with the applicable portions of this subpart.

40 CFR Part 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines"

This subpart applies to all turbines with heat input in excess of 10 MMBTU/Hr that commence construction after February 18, 2005. The proposed GE 7HA.01 gas turbine is subject to the subpart because the heat input for the turbine is 2,572 MMBTU/Hr. The turbine is a simple cycle turbine without heat recovery and does not utilize water or steam injection for emissions control. The turbine will be fired on only PUC regulated natural gas.

Section 60.4320 requires turbines to meet the applicable NO_x standard in Table 1 of the subpart. The proposed natural gas fired turbine is over 850 MMBTU/Hr, therefore the NO_x limit as listed in Table 1 is 15 ppmvd at 15% O₂ or 0.43 lb/MW-Hr. This Subpart KKKK NO_x limit is less stringent than District Rule 74.23 limit (9 ppmvd NO_x) and the District Rule 26.2.A NSR BACT limit of 2.5 ppmvd NO_x for the unit. Therefore, new turbine compliance with the District NSR BACT requirements will comply with the Subpart KKKK.

Section 60.4330 requires the turbine to meet the SO₂ emission limits. The turbine will be fired on PUC regulated natural gas therefore the SO₂ emissions limits are either 0.90 lbs-SO₂/MWh discharge based on gross output (Section 60.4330 (a)(1)) or 0.060 lbs-SO₂/MMBTU potential in the fuel (Section 60.4330 (a)(2)). The natural gas sulfur content of the fuel will be limited to 0.75 grain per 100 scf (0.0021375 lbs- SO₂/MMBTU). This sulfur content is lower than the fuel sulfur standard. Therefore, the new turbine will comply with this section.

Section 60.4333 is a general requirement that requires the operation and maintenance of the turbine in a manner of good air pollution control practices at all times. The facility will be required to operate the turbine in this manner.

Section 60.4340 provides guidance on requirements when there is no water or steam injection being used to control NO_x emissions. The section requires either annual source testing to show NO_x compliance or installation of a continuous emission monitoring system (CEMS) as described in 60.4335(b) and 60.4345 be used. The facility has proposed to install and operate a CEMS which will comply with these sections.

Section 60.4345 contains requirements for the CEMS system. The CEMS may either be certified using either Performance Specification 2 (PS 2) of Appendix B of 40 CFR Part 60 (except 7-day drift test is based on unit operating days instead of calendar days), or according to the procedures of Appendix A of 40 CFR Part 75. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBTU basis. For each full unit operating hour, the NO_x and diluent monitors must sample, analyze and record at least once each 15 minute quadrant for the hour to be valid. For partial unit operating hours, at least one valid point must be obtained for each quadrant of the hour the turbine operates. Only two valid points are needed for hours in which quality assurance or maintenance

activities are conducted to validate the hour. All monitors including fuel flowmeters, watt meters, temperature sensors, etc. must be installed, calibrated, maintained and operated according to manufacturer's instructions. The facility must maintain a quality assurance (QA) plan for all continuous monitoring equipment.

Section 60.4350 contains requirements for using CEMS data to identify excess emissions. This includes that all CEMS data be reduced to hourly averages and recorded in units of ppm (uncorrected) or lb/MMBTU for each valid unit operating hour of data. For missing data, the owner or operator is not required to report data substituted using the missing data procedures of 40 CFR Part 75, and instead may report these periods as monitor downtime. All other monitored parameters must be reduced to hourly averages as well. For simple-cycle units, excess emissions are calculated on a 4-hour rolling average basis as required by Section 60.4350(g).

Sections 60.4360 and 60.4365 have requirements for monitoring sulfur content of fuel. Since only natural gas is combusted, sulfur content monitoring is not required per 60.4365(a) which specifies that, if a purchase contract, tariff sheet, or transportation contract lists sulfur content below 20 grains of sulfur per 100 standard cubic feet (scf) of gas, no monitoring is required. As discussed above, the natural gas sulfur content of the fuel will be limited to 0.75 grains of sulfur per 100 scf. The Puente Power Project will be required to keep records of fuel natural gas sulfur content.

Section 60.3475 requires the submission of reports of excess emissions and monitor downtime (including startups, shutdowns and malfunctions).

Section 60.4380 specifies that periods of excess emissions to be reported are any time where the 4-hour NO_x emission rate exceeds the applicable standard of 15 ppmvd at 15% O₂. The 4-hour average includes the unit operating hour and three unit operating hours immediately preceding the subject unit operating hour. An emission rate is calculated if a valid NO_x rate is obtained for at least three out of four hours. Periods of monitor downtime to be reported include any hours the turbine was operating but valid readings were not obtained. For periods where multiple emission limits would apply (i.e. the 4-hour averaging period includes periods of operating both above and below 75% load), the applicable standard is the average of the applicable standards during each hour. For each hour where multiple emission standards apply, the higher emission standard during that hour applies.

Section 60.4395 requires that reports be submitted by the 30th day following the end of each semi-annual reporting period. This is specified in proposed permit conditions.

Sections 60.4400 and 60.4405 contain instructions for initial and periodic source testing. If testing is to be performed, EPA Method 7E or Method 20 may be used to measure NO_x concentration along with EPA Methods 1 and 2 to determine stack gas flow rate or NO_x and O₂ may be measured using Method 20 or Methods 7E and 3A, and then converted to lb/MMBTU using EPA Method 19. Alternatively, if equipped with a CEMS, the initial performance test may be conducted as a RATA test. An additional requirement is that the test be conducted while the turbine is operating within +/- 25% of 100% peak load. This is specified in the proposed permit conditions.

Compliance with the requirements of 40 CFR Part 60 Subpart KKKK is expected.

40 CFR Part 60, Subpart TTTT, “Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units”

This subpart applies to stationary combustion turbines that commence construction after January 8, 2014.

Section 60.5520 (a) requires the turbine to meet the applicable standard for CO₂ emissions as determined in either table 1 or 2 of the subpart. In this case the NRG P3 turbine must meet the table 2 emission standard of 50 kg CO₂ per gigajoule (GJ) of heat input (120 lb CO₂/MMBTU).

Table 2 of NSPS Subpart TTTT CO ₂ Emission Standards for Stationary Combustion Turbines	
Affected EGU	CO ₂ Emission Standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO ₂ per gigajoule (GJ) of heat input (120 lb CO ₂ /MMBTU).

“Design efficiency” is defined in the rule as “the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions”

“Potential electric output” is defined in the rule as “33 percent or the base load rating design efficiency at the maximum electric production rate ..., whichever is greater, multiplied by the base load rating (expressed in MMBTU/h) of the EGU, multiplied by 106 BTU/ MMBTU, divided by 3,413 BTU/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr...” Based on the current ISO heat rate of 8,317 BTU/kWh (electrical) (LHV) and a conversion factor of 3412.1416 BTU/kWh (thermal), it takes 2.4375 kWh (thermal) input to produce 1 kWh (electrical) output (8317 BTU/kWh ÷ 3412.1416 BTU/kWh = 2.4375). The base load rating design efficiency for the P3 CTG is therefore 1 kWh (electrical) / 2.4375 kWh (thermal) = 41%.

The percentage electric sales threshold that distinguishes base load and non-base load units is based on the specific turbine’s design efficiency (commonly known as “the sliding-scale approach”) and varies from 33 to 50 percent. Specifically, all units that have annual average electric sales (expressed as a capacity factor) greater than their net lower heating value (LHV) design efficiencies (as a percentage of potential electric output) are base load units. All units that have annual average electric sales (expressed as a capacity factor) less than or equal to their net LHV design efficiencies are non-base load units. As discussed above, it is expected that on an annual average basis the new P3 CTG would

supply less than one-third of its potential electric output to a utility power distribution system. Because this expected potential annual average electric sales rate is less than the 41% design efficiency, the new P3 CTG would be a non-base load unit under the final CPS. As a non-base load unit, under the final CPS the potential electric output for P3 is calculated as follows:

Potential electric output =

$$\begin{aligned}
 &= \text{Design efficiency (\%)} \times \text{Heat Input Rate, } \frac{\text{MMBtu}}{\text{hr}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} \times \frac{1 \text{ kWh}}{3412.1416 \text{ Btu}} \times \frac{1 \text{ MWh}}{1,000 \text{ kWh}} \times 8,760 \text{ hrs/yr} \\
 &= 0.41 \times 2,567.81 \frac{\text{MMBtu}}{\text{hr}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} \times \frac{1 \text{ kWh}}{3412.1416 \text{ Btu}} \times \frac{1 \text{ MWh}}{1,000 \text{ kWh}} \times 8,760 \text{ hrs/yr} \\
 &= 2,702,862 \text{ MW per year}
 \end{aligned}$$

As long as the P3 CTG has net electric sales of less than $0.41 \times 2,702,862 \text{ MW}$, or $1,108,173 \text{ MW per year}$, it will be subject to the $120 \text{ lb CO}_2/\text{MMBTU}$ limit for non-base load gas turbines. The new P3 CTG is expected to operate with an annual capacity factor of approximately 25%. With a full load net nominal output of approximately 262 MW, the P3 unit would supply a maximum of approximately $25\% \times 8760 \text{ hrs/year} \times 262 \text{ MW/Hr} = 573,780 \text{ MW per year}$ to a utility power distribution system. Since this output is less than the allowable level of $1,108,173 \text{ MW per year}$, the P3 CTG would be a non-base load unit under the final CPS and would be subject to the Best System of Emission Reduction (BSER) established for that subcategory.

Section 60.5525 and 60.5535 has the general requirements and monitoring for complying with the subpart. This turbine is limited to burning natural gas resulting in a consistent emission rate of $120 \text{ lb CO}_2/\text{MMBTU}$ or less per section 60.5520(d)(1). Therefore, the facility will be required to maintain fuel purchase records of the natural gas.

40 CFR Part 63 Subpart ZZZZ – Reciprocating Internal Combustion Engines (RICE)

This NESHAP rule applies to the new emergency diesel engine. It applies to all reciprocating internal combustion engines (RICE) located at both major and area sources of HAPs. This rule is delegated to the Ventura County APCD for implementation by the EPA.

As discussed above, this site is not a major HAPs source. This rule has the following limited exemptions:

Section 40 CFR 63.6590(c)(1) lists new RICE at an area HAPS source complies with NESHAP Subpart ZZZZ by complying with the corresponding New Source Performance Standard - NSPS, 40 CFR 60 Subpart IIII for stationary compression ignition engines.

The proposed emergency engine will comply with NSPS IIII as discussed above and will therefore comply with NESHAPS ZZZZ.

40 CFR Part 64, “Compliance Assurance Monitoring”

The Compliance Assurance Monitoring (CAM) regulation applies to emission units at a major stationary source required to obtain a Title V permit, which use control equipment to achieve a specified emission limit. The section is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits. CAM is applicable to the turbine because the potential to emit for the stationary source exceeds the major source thresholds (25 tons per year for ROC or NO_x, and 100 tons per year for PM, SO_x, or CO) for NO_x and CO. However, based on section 64.2(b)(1)(vi), NO_x and CO emission are exempt from CAM since the Part 70 permit for the turbine already requires a continuous compliance determination method for both NO_x and CO. The turbine will have a CEM installed which will comply with this requirement.

40 CFR Part 68, List of Regulated Substances and Thresholds for Accidental Release Prevention

This regulation addresses the risk management plan (RMP) requirements of section 112(r) of the federal Clean Air Act. 40 CFR Part 68 applies to regulated substances that are contained in a process at this facility that exceed the threshold quantity, as presented in 40 CFR Part 68.130. The Selective Catalytic Reduction (SCR) system for NO_x control at the CTG uses aqueous ammonia with a concentration of less than 20% by weight. However, aqueous ammonia must be greater than or equal to 20% by weight ammonia in order to be one of the regulated toxic substances listed in 40 CFR Part 68.130. Therefore, facility is not subject to 40 CFR Part 68.

40CFR Part 75 – Continuous Emission Monitoring (CEMS)

The new turbine combusts only natural gas, it is only required to monitor NO_x and CO₂ (or O₂) and has the choice of monitoring SO_x or may use fuel flow monitoring and default sulfur emission factors to calculate emissions. Additionally Subpart C of this part contains requirements for operating and maintaining the CEMS to ensure that accurate, valid data is collected. The CEMS is required to be initially certified and requires recertification if certain modifications are made. Required QA activities include linearity checks, 7-day calibration error tests, and relative accuracy test audits (RATA). Linearity and calibration error tests ensure that the monitors are measuring emissions accurately. RATA compare the CEMS readings to the results determined using a source test. The RATA must be conducted annually except in certain situations where the turbine does not operate for more than 168 hours per calendar quarter. Finally, this part contains requirements for substituting data in a conservative manner for any hour when the CEMS does not record valid data, and these requirements are specified in the proposed permit conditions. Additionally the facility is required to operate according to an approved CEMS protocol, which will contain the above requirements and specific procedures in detail.

IX. Recommendation

Compliance with all applicable District, State, and Federal rules and regulations is expected. Issue the Determination of Compliance for the facility subject to the conditions presented in Appendix K.

Appendices:

Appendix A	Current Permitted Emissions
Appendix B	Emissions Data
Appendix C	Commissioning Schedule
Appendix D	Historical Fuel Records
Appendix E	ERCs Identified For Possible Use
Appendix F	ERC Profile Check
Appendix G	Ambient Air Quality Analysis and Risk Management Review
Appendix H	Hazardous Air Pollutant Stationary Source Potential to Emit
Appendix I	Certification of Statewide Compliance
Appendix J	Analysis of Alternatives
Appendix K	Draft DOC Conditions

Appendix A

Current Permitted Emissions

PEETS PERMIT ONLY - NOT MAILED

Number 00013

Valid July 1, 2015 to June 30, 2016

This Permit Has Been Issued To The Following:

Company Name / Address:

NRG California South LP
393 North Harbor Blvd.
Oxnard, CA 93035

Facility Name / Address:

Mandalay Generating Station
393 North Harbor Blvd.
Oxnard, CA 93035

Permission Is Hereby Granted To Operate The Following:

- 1 - 1990 MMBTU/hr Babcock and Wilcox, rated at 215 MW, Steam Generator (Unit No. 1), equipped with a SCR with NH3 Injection and Low NOx combustion system
- 1 - 1990 MMBTU/hr Babcock and Wilcox, rated at 215 MW, Steam Generator (Unit No. 2), equipped with a SCR with NH3 Injection
- 1 - 2510 MMBTU/hr Turbine Peaking Unit (Unit No. 3)
- 1 - 14650 Gallon Aqueous Ammonia Storage Tank
- 1 - 201 BHP Generac Diesel-Fired Emergency Standby Engine, Model 96A-00728-5, Serial No. 2025978, for emergency electricity generation
- 1 - 154 BHP Perkins England Diesel-Fired Emergency Standby Engine, Model 1006-GT, Serial No. 97-280426-00.001, used for fire suppression

This Permit Has Been Issued Subject To The Following Conditions:

- | 1. Permitted Emissions | Tons/Year | Pounds/Hour |
|------------------------|-----------|-------------|
| Reactive Organics | 23.99 | 23.47 |
| Nitrogen Oxides | 222.74 | 1,146.00 |
| Particulate Matter | 43.52 | 58.10 |
| Sulfur Oxides | 10.02 | 3.72 |
| Carbon Monoxide | 675.52 | 427.98 |
| Ammonia | 78.03 | 17.82 |
2. For permit conditions, see Title V permit, valid January 1, 2014 to December 31, 2018.

Within 30 days after receipt of this permit, the permittee may petition the Hearing Board to review any new or modified condition (Rule 22).

This permit, or a copy, shall be posted reasonably close to the subject equipment and shall be accessible to inspection personnel (Rule 19). This permit is not transferable from one location to another unless the equipment is specifically listed as being portable (Rule 20).

VCAPCD Permit To Operate Number 00013
Issued To Mandalay Generating Station
Valid July 1, 2015 to June 30, 2016

This Permit to Operate shall not be construed to allow any emission unit to operate in violation of any state or federal emission standard or any rule of the District.

For:

Terri Thomas
Engineering Division

Michael Villegas
Air Pollution Control Officer

Permitted Emissions Summary

Criteria Pollutants

00013-381 Mandalay Generating Station

Permit Period: 7/1/2015 to 6/30/2016

Equipment	Tons per Year					Pounds Per Hour				
	ROC	NOx	PM	SOx	CO	ROC	NOx	PM	SOx	CO
1 - 1990 MMBTU/hr Babcock and Wilcox, rated at 215 M	23.24	176.98	41.51	9.96	664.09	5.31	40.41	9.48	2.27	151.62
1 - 2510 MMBTU/hr Turbine	0.75	45.64	2.01	0.06	11.41	18.07	1104.41	48.53	1.43	276.10
1 - 201 BHP Generac Diesel-Fired Emergency Standby En	0.00	0.07	0.00	0.00	0.01	0.05	0.67	0.05	0.01	0.15
1 - 154 BHP Perkins England Diesel-Fired Emergency Stan	0.00	0.05	0.00	0.00	0.01	0.04	0.51	0.04	0.01	0.11
Total	23.99	222.74	43.52	10.02	675.52	23.47	1146.00	58.10	3.72	427.98

Also has Other Pollutants-See Inorganic Compounds Summary

Permitted Emissions Summary

Inorganic Compounds

00013-381 Mandalay Generating Station

Permit Period: 7/1/2015 to 6/30/2016

Equipment	Tons per Year				Pounds Per Hour			
	NH3	Cl2	HCl	H2S	NH3	Cl2	HCl	H2S
1 - 1990 MMBTU/hr Babcock and Wilcox, rated at 215 M	78.03	0.00	0.00	0.00	17.82	0.00	0.00	0.00
1 - 2510 MMBTU/hr Turbine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1 - 201 BIP Generac Diesel-Fired Emergency Standby En	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1 - 154 BIP Perkins England Diesel-Fired Emergency Stan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	78.03	0.00	0.00	0.00	17.82	0.00	0.00	0.00

Also has Criteria Pollutants-See Criteria Pollutants Summary

Equipment and Emissions Summary

00013 - 381 Mandalay Generating Station Permit Period: 7/1/2015 to 6/30/2016 SIC Code 4911 - Electricity Generation

DEVICE NO: 10353 1 - 1990 MMBTU/hr Babcock and Wilcox, rated at 215 MW, Steam Generator (Unit No. 1), equipped with a SCR with NH3 Injection and Low NOx combustion system

SOURCE CLASSIFICATION CODE		SCC Units		Prmt Annual Throughput		Max Hourly Throughput				Hours Per Year (if used)
10100601 - Utility Boiler - Nat Gas		MMcf		33204.6000 MMcf		3980.0000 MMBTU NG				
POLLUTANT	Tons/Yr	Lbs/Hr	Uncntl EF	Cntl Factor	Cntl EF	APE?	HPE?	EF Over	CF Over	Control Device
Reactive Organics	23.24	5.31	1.4000	1.0000	1.4000	Y	Y		Y	Selective Cat Rdxn (SCR)
Nitrogen Oxides	176.98	40.41	10.6600	1.0000	10.6600	Y	Y	Y	Y	
Particulate Matter	41.51	9.48	2.5000	1.0000	2.5000	Y	Y		Y	
Sulfur Oxides	9.96	2.27	0.6000	1.0000	0.6000	Y	Y		Y	
Carbon Monoxide	664.09	151.62	40.0000	1.0000	40.0000	Y	Y		Y	
Ammonia	78.03	17.82	4.7000	1.0000	4.7000	Y	Y	Y	Y	

DEVICE NO: 10355 1 - 2510 MMBTU/hr Turbine Peaking Unit (Unit No. 3)

SOURCE CLASSIFICATION CODE			SCC Units		Prmt Annual Throughput		Max Hourly Throughput			Hours Per Year (if used)	
20100201 - Turbine-Natural Gas			MMcf		197.5800 MMcf		2510.0000 MMBTU NG				
POLLUTANT	Tons/Yr	Lbs/Hr	Uncntl EF	Cntl Factor	Cntl EF	APE?	HPE?	EF Over	CF Over	Control Device	
Reactive Organics	0.75	18.07	7.5600	1.0000	7.5600	Y	Y	Y	Y		
Nitrogen Oxides	45.64	1104.41	462.0000	1.0000	462.0000	Y	Y	Y	Y		
Particulate Matter	2.01	48.53	20.3000	1.0000	20.3000	Y	Y	Y	Y		
Sulfur Oxides	0.06	1.43	0.6000	1.0000	0.6000	Y	Y			Y	
Carbon Monoxide	11.41	276.10	115.5000	1.0000	115.5000	Y	Y	Y	Y		

DEVICE NO: 17509 1 - 201 BHP Generac Diesel-Fired Emergency Standby Engine, Model 96A-00728-5, Serial No. 2025978, for emergency electricity generation

SOURCE CLASSIFICATION CODE			SCC Units		Prmt Annual Throughput		Max Hourly Throughput			Hours Per Year (if used)	
20200103 - Diesel ICE - g/hp-hr<1000			BHP-g<1000		4020.0000 BHP-d<1000		20.1000 BHP-d<1000			Calculate Hourly Using 200 Hrs/Yr	
POLLUTANT	Tons/Yr	Lbs/Hr	Uncntl EF	Cntl Factor	Cntl EF	APE?	HPE?	EF Over	CF Over	Control Device	
Reactive Organics	0.00	0.05	1.0700	1.0000	1.0700	Y	Y			Y	
Nitrogen Oxides	0.07	0.67	15.1000	1.0000	15.1000	Y	Y			Y	
Particulate Matter	0.00	0.05	1.0800	1.0000	1.0800	Y	Y			Y	
Sulfur Oxides	0.00	0.01	2.4200	0.1000	0.2400	Y	Y			Y	Low Sulfur 0.05 fuel
Carbon Monoxide	0.01	0.15	3.2800	1.0000	3.2800	Y	Y			Y	

Equipment and Emissions Summary

00013 - 381 Mandalay Generating Station Permit Period: 7/1/2015 to 6/30/2016 SIC Code 4911 - Electricity Generation

DEVICE NO: 17510 1 - 154 BHP Perkins England Diesel-Fired Emergency Standby Engine, Model 1006-GT, Serial No. 97-280426-00.001, used for fire suppression

SOURCE CLASSIFICATION CODE	SCC Units	Prmt Annual Throughput	Max Hourly Throughput	Hours Per Year (if used)
20200103 - Diesel ICE - g/hp-hr<1000	BHP-g<1000	3080.0000 BHP-d<1000	15.4000 BHP-d<1000	Calculate Hourly Using 200 Hrs/Yr

POLLUTANT	Tons/Yr	Lbs/Hr	Uncntl EF	Cntl Factor	Cntl EF	APE?	HPE?	EF Over	CF Over	Control Device
Reactive Organics	0.00	0.04	1.0700	1.0000	1.0700	Y	Y		Y	
Nitrogen Oxides	0.05	0.51	15.1000	1.0000	15.1000	Y	Y		Y	
Particulate Matter	0.00	0.04	1.0800	1.0000	1.0800	Y	Y		Y	
Sulfur Oxides	0.00	0.01	2.4200	0.1000	0.2400	Y	Y		Y	Low Sulfur 0.05 fuel
Carbon Monoxide	0.01	0.11	3.2800	1.0000	3.2800	Y	Y		Y	

Appendix B

Emissions Data

Table B-1 (Revised December 4, 2015)
Puente Power Project
Performance Runs for Gas Turbine

Ambient Condition	Winter	Winter	ISO	ISO	Summer	Summer	Summer	Summer	Summer	Summer
Ambient Temperature (deg. F)	38.9	38.9	59	59	77.8	77.8	77.8	82	82	82
Relative Humidity, %	26%	26%	60%	60%	50%	50%	50%	31%	31%	31%
Load	Maximum	Minimum	Maximum	Minimum	Maximum	Maximum	Minimum	Maximum	Maximum	Minimum
Evap Cooling?	Off	Off	Off	Off	On	Off	Off	On	Off	Off
Output Summary										
Gross Output, MW	280	70	276	69	270	258	76	272	254	77
HHV Fuel Input, MMBtu/hr	2,572.07	1,080.07	2,552.16	1,057.38	2,507.74	2,417.99	1,083.67	2,521.81	2,384.57	1,101.53
Fuel Flow, scf/hr	2,523,252	1,059,268	2,502,903	1,037,111	2,459,944	2,371,766	1,072,608	2,473,510	2,337,851	1,080,295
Stack Parameters										
Stack Exhaust Flow, 100s lb/hr	6,109.00	3,316.00	6,197.00	3,297.00	6,158.00	6,089.00	3,398.00	6,193.00	6,012.00	3,433.00
Stack Exhaust Temperature, Deg.F	900	900	900	900	900	900	900	900	900	900
Exhaust Composition, Vol %										
N2	75.50%	76.04%	74.94%	75.46%	74.31%	74.58%	75.02%	74.53%	74.93%	75.36%
O2	14.03%	15.57%	14.04%	15.50%	13.95%	14.11%	15.38%	14.00%	14.26%	15.48%
CO2	3.19%	2.48%	3.12%	2.44%	3.07%	3.02%	2.44%	3.07%	3.01%	2.44%
H2O	6.38%	4.99%	7.00%	5.69%	7.77%	7.39%	6.27%	7.50%	6.91%	5.82%
Ar	0.91%	0.91%	0.91%	0.90%	0.89%	0.89%	0.89%	0.89%	0.89%	0.91%
Molecular Weight	28.56	28.64	28.48	28.56	28.39	28.43	28.5	28.42	28.48	28.55
Stack Exhaust Flow, 100s ACFM	3,530.67	1,922.03	3,587.69	1,915.87	3,576.29	3,485.05	1,977.90	3,592.25	3,482.77	1,995.01
Stack Emission Rates										
NOx, ppmvd@5% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CO, ppmvd@5% O2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
ROCas CH4, ppmvd@5% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NH3, ppmvd@5% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Particulates, lb/hr	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
NOx, lb/hr	23.1	9.7	22.9	9.5	22.5	21.7	9.8	22.6	21.4	9.9
CO, lb/hr	22.5	9.4	22.3	9.2	21.9	21.2	9.5	22.1	20.9	9.6
ROCas CH4, lb/hr	6.4	2.7	6.4	2.6	6.3	6.1	2.7	6.3	6.0	2.8
NH3 Slip, lb/hr	17.1	7.2	17.0	7.0	16.7	16.1	7.3	16.8	15.9	7.3

Table B-2 (Revised December 4, 2015)
Puerto Power Project
Gas Turbine Hourly Emissions - Startup/Shutdown Emissions

Gas Turbine - Hourly Startup Emissions

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	ROC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	ROC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Startup Emissions	30	N/A	N/A	N/A	N/A	5.4	87.0	167.0	17.0	3.7	2.7
Maximum Normal Operation Emissions	30	23.1	22.5	6.4	10.1	5.4	11.6	11.3	3.2	5.1	2.7
Total =	60						98.6	178.3	20.2	8.8	5.4

Gas Turbine - Hourly Shutdown Emissions

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	ROC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	ROC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Shutdown Emissions	12	N/A	N/A	N/A	N/A	5.4	4.0	145.0	25.0	1.5	1.1
Maximum Normal Operation Emissions	48	23.1	22.5	6.4	10.1	5.4	18.5	18.0	5.2	8.1	4.3
Total =	60						22.5	163.0	30.2	9.6	5.4

Gas Turbine - Hourly Startup/Shutdown/Restart Emissions

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	ROC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	ROC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Startup Emissions	30	N/A	N/A	N/A	N/A	5.4	87.0	167.0	17.0	3.7	2.7
Maximum Shutdown Emissions	12	N/A	N/A	N/A	N/A	5.4	4.0	145.0	25.0	1.5	1.1
Maximum Restart Emissions*	18	N/A	N/A	N/A	N/A	5.4	52.2	100.2	10.2	2.2	1.6
Total =	60						143.2	412.2	52.2	7.4	5.4

Note: * Calculated based on maximum startup emissions reduced for 18 minute period.



October 28, 2015

To: NRG Puente Power Team

Subject: NRG Puente Power
GE IPS: 976085
GE PM10 Emission Guarantee

The NRG Puente Power Plant, will utilize the 7HA.01 gas turbine technology installed in a simple cycle configuration equipped with an air attemperated simple cycle SCR and CO catalyst. For this installation, GE is offering a Particulate Matter emission guarantee of 10.1 lbs/hr as measured at the emission sampling ports located at the turbine stack exit. This guarantee shall apply for the entire load range from minimum emission compliant load (MECL) through base load operation and across the guarantee ambient temperature range of 38.9 to 82 deg F.

Regards,

A handwritten signature in black ink, appearing to read 'Andrew Dicke'.

Andrew Dicke
GE Power and Water
Emissions and Permitting Application Engineer

Appendix C

Commissioning Schedule

Table B-4 (Revised December 4, 2015)
Puente Power Project
Gas Turbine Commissioning Schedule

						Total Emissions					Calculated Hourly Emissions (lbs/hr)							
Day	Activity	Duration (hr)	GT Load (%)	No. of GT Shutdowns	Daily Fuel Consumption (MMSCF-HHV)	Daily Energy Production (MWh)	NOx (lbs)	CO (lbs)	ROC (lbs)	PM10 (lbs)	SOx (lbs)	SCR (Y/N)	Nox	CO	ROC	PM10*	SOx*	
1	GT Testing (1st Fire, FSNL)	8	0	1	4.8	0.0	1076.5	15783.7	1312.9	85.2	9.9	N	134.6	1,973.0	164.1	10.1	5.4	
2	GT Testing (FSNL, Excitation Test, Dummy Synch Checks)	8	0	1	4.8	0.0	1076.5	15783.7	1312.9	85.2	9.9	N	134.6	1,973.0	164.1	10.1	5.4	
3	GT Testing / Initial 4 Hour Run / Overspeed Testing	8	0-50	1.0	13.9	1,091.3	1560.2	6163.1	544.6	86.9	28.5	N	195.0	770.4	68.1	10.1	5.4	
4	Base Load Run-In Lean-Lean for Strainer Cleanliness	10	100	1.0	27.6	2,750.0	2443.7	830.2	107.8	111.2	56.6	N	244.4	83.0	10.8	10.1	5.4	
5	GT Testing / DLN Tuning	8	0-50	1.0	13.9	1,091.3	1560.2	6163.1	544.6	86.9	28.5	N	195.0	770.4	68.1	10.1	5.4	
6	GT Testing / DLN Tuning	8	0-50	1.0	13.9	1,091.3	1560.2	6163.1	544.6	86.9	28.5	N	195.0	770.4	68.1	10.1	5.4	
7	GT Testing / DLN Tuning	8	50-75	1.0	18.3	1,652.2	1174.0	498.5	58.0	88.3	37.4	N	146.8	62.3	7.3	10.1	5.4	
8	GT Testing / DLN Tuning	8	50-75	1.0	18.3	1,652.2	1174.0	498.5	58.0	88.3	37.4	N	146.8	62.3	7.3	10.1	5.4	
9	GT Testing / DLN Tuning	8	75-100	1.0	22.4	2,214.8	1970.8	726.5	94.6	90.0	45.9	N	246.3	90.8	11.8	10.1	5.4	
10	GT Testing / DLN Tuning	8	75-100	1.0	22.4	2,214.8	1970.8	726.5	94.6	90.0	45.9	N	246.3	90.8	11.8	10.1	5.4	
11	No Operation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N						
12	Load Catalyst	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N						
13	Load Catalyst	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N						
14	Load Catalyst	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N						
15	Load Catalyst	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N						
16	GT Base Load / Commissioning of Ammonia system	16	50-100	1.0	43.3	4,355.6	457.4	680.5	147.3	174.8	88.7	Y	28.6	42.5	9.2	10.1	5.4	
17	GT Load Test	12	100	1.0	32.9	3,285.2	362.8	588.4	121.0	132.4	67.3	Y	30.2	49.0	10.1	10.1	5.4	
18	No Operation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
19	Install Emissions Test Equipment	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
20	Emissions Tuning / Drift Test	12	50-100	1.0	32.9	3,285.2	362.8	588.4	121.0	132.4	67.3	Y	30.2	49.0	10.1	10.1	5.4	
21	Emissions Tuning / Drift Test	12	50-100	1.0	32.9	3,285.2	362.8	588.4	121.0	132.4	67.3	Y	30.2	49.0	10.1	10.1	5.4	
22	Pre-performance Testing / Drift Test	16	100	1.0	43.3	4,355.6	457.4	680.5	147.3	174.8	88.7	Y	28.6	42.5	9.2	10.1	5.4	
23	Pre-performance Testing / Drift Test	16	100	1.0	43.5	4,386.6	469.4	616.5	140.3	174.8	89.2	Y	29.3	38.5	8.8	10.1	5.4	
24	Pre-performance Testing / Drift Test	16	100	1.0	43.5	4,386.6	469.4	616.5	140.3	174.8	89.2	Y	29.3	38.5	8.8	10.1	5.4	
25	RATA / Pre-performance Testing / Source Testing	16	100	1.0	43.3	4,355.6	457.4	680.5	147.3	174.8	88.7	Y	28.6	42.5	9.2	10.1	5.4	
26	RATA / Pre-performance Testing / Source Testing	16	100	1.0	43.5	4,386.6	469.4	616.5	140.3	174.8	89.2	Y	29.3	38.5	8.8	10.1	5.4	
27	Pre-performance Testing / Source Testing	16	100	1.0	43.5	4,386.6	469.4	616.5	140.3	174.8	89.2	Y	29.3	38.5	8.8	10.1	5.4	
28	Pre-performance Testing / Source Testing	16	50-100	1.0	43.5	4,386.6	469.4	616.5	140.3	174.8	89.2	Y	29.3	38.5	8.8	10.1	5.4	
29	Remove Emissions Test Equipment	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
30	Torque Exhaust Bolts & Remove A179 Strainers	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
31	Torque Exhaust Bolts & Remove A179 Strainers	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
32	Torque Exhaust Bolts & Remove A179 Strainers	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
33	Water Wash & Performance preparation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
34	Water Wash & Performance preparation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
35	Water Wash & Performance preparation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
36	Performance/Reliability Testing	24	100	0.0	64.4	6,525.3	654.5	655.7	167.9	258.1	131.8	Y	27.3	27.3	7.0	10.1	5.4	
37	Performance/Reliability Testing	24	100	1.0	62.7	6,424.3	571.5	697.7	182.9	255.9	128.3	Y	23.8	29.1	7.6	10.1	5.4	
38	No Operation	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Y						
39	SCE 72 Hour Test - Day 1	24	50-100	0.0	64.4	6,525.3	654.5	655.7	167.9	258.1	131.8	Y	27.3	27.3	7.0	10.1	5.4	
40	SCE 72 Hour Test - Day 2	24	50-100	0.0	62.6	6,422.3	567.5	552.7	157.9	254.4	128.2	Y	23.6	23.0	6.6	10.1	5.4	
41	SCE 72 Hour Test - Day 3	24	50-100	1.0	62.7	6,424.3	571.5	697.7	182.9	255.9	128.3	Y	23.8	29.1	7.6	10.1	5.4	
Total GT operation hours =		366						23,393.9	63,485.9	7,038.4	3,976.9	1,890.8	max =	246.3	1,973.0	164.1	10.1	5.4
							11.7	31.7	3.5	2.0	0.9							

Appendix D

Historical Fuel Records

2010 Mandalay Generating Station Fuel Use

Equipment	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
Unit 1 (MMscf)	4.8	23.7	0.0	0.4	0.0	0.7	83.8	106.5	19.7	34.6	14.7	25.4	314.3
Unit 2 (MMscf)	77.3	23.1	0.6	0.0	0.0	0.9	178.7	127.4	59.1	73.6	22.6	24.4	587.6
Unit 3 (MMscf)	0.7	1.7	0.0	1.4	0.5	2.5	5.7	7.2	12.4	7.1	2.9	0.1	42.4
Emergency Gen. Engine (gallons)	15.2	0.0	0.4	0.0	0.4	0.4	0.4	1.1	0.4	0.4	0.4	0.4	19.5
Emergency Firepump Engine (gallons)	0.3	0.3	0.3	0.0	0.0	0.3	0.6	0.6	0.3	0.3	0.3	0.6	3.8

2011 Mandalay Generating Station Fuel Use

Equipment	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
Unit 1 (MMscf)	82.5	0.0	0.0	6.2	0.0	53.6	91.0	50.1	50.2	0.0	0.6	0.0	334.2
Unit 2 (MMscf)	100.9	4.8	0.0	74.7	110.0	19.0	0.0	53.1	67.0	29.0	35.3	13.9	507.8
Unit 3 (MMscf)	0.0	0.0	1.4	2.7	5.0	9.6	2.1	0.0	4.3	2.6	2.6	0.0	30.4
Emergency Gen. Engine (gallons)	0.4	0.7	0.4	0.4	1.1	0.7	0.0	0.7	0.4	0.4	0.4	0.4	5.9
Emergency Firepump Engine (gallons)	0.3	0.6	0.3	0.6	0.3	0.6	0.3	0.3	0.3	0.3	0.3	0.3	4.4

2012 Mandalay Generating Station Fuel Use

Equipment	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
Unit 1 (MMscf)	49.0	22.3	0.5	0.0	83.9	49.9	155.9	387.5	79.1	106.7	143.7	61.7	1140.2
Unit 2 (MMscf)	0.3	0.0	0.0	16.6	106.5	74.1	86.1	380.2	269.9	101.7	89.1	42.1	1166.5
Unit 3 (MMscf)	0.1	0.3	0.0	12.5	7.1	9.4	7.3	5.7	24.9	13.7	9.8	18.7	109.6
Emergency Gen. Engine (gallons)	0.4	0.0	0.4	0.4	0.4	0.7	0.4	0.4	0.0	0.4	0.0	0.4	3.7
Emergency Firepump Engine (gallons)	0.3	0.3	0.6	0.0	0.0	0.6	0.0	0.0	0.3	0.3	0.0	0.3	2.6

2013 Mandalay Generating Station Fuel Use

Equipment	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
Unit 1 (MMscf)	143.6	0.6	0.0	0.0	127.0	125.4	122.7	46.8	71.5	48.8	191.9	184.8	1063.2
Unit 2 (MMscf)	104.4	14.6	201.6	141.5	178.1	151.9	97.6	67.1	86.1	37.8	158.5	189.8	1429.0
Unit 3 (MMscf)	8.5	5.5	4.7	0.1	4.1	0.2	2.2	21.4	19.8	0.0	0.0	0.9	67.5
Emergency Gen. Engine (gallons)	0.7	0.4	0.4	0.7	0.0	0.7	0.7	0.4	0.4	0.4	0.4	0.4	5.6
Emergency Firepump Engine (gallons)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.3	0.6	0.6	2.0

2014 Mandalay Generating Station Fuel Use

Equipment	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total
Unit 1 (MMscf)	89.0	19.7	6.0	60.8	37.9	9.4	25.8	41.4	70.3	191.9	86.7	108.3	747.2
Unit 2 (MMscf)	143.8	79.6	3.4	130.7	41.6	9.1	47.1	50.3	40.0	183.0	42.6	57.6	828.9
Unit 3 (MMscf)	0.9	2.3	1.5	1.4	1.3	0.0	4.6	4.5	2.9	0.0	0.9	1.5	21.8
Emergency Gen. Engine (gallons)	0.0	2.3	2.3	3.5	10.5	1.2	1.2	2.3	1.2	1.2	1.2	1.2	28.1
Emergency Firepump Engine (gallons)	0.0	0.7	0.7	0.7	0.7	0.7	0.0	1.4	0.7	0.7	0.7	0.7	7.7

Appendix E

ERCs Identified for possible use

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1078

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	3.66
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.02

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Santa Paula NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	9/16/1992	00053-151	5.91	7.13	0.40	0.02
Electrify Texaco S Mtn Compressor Plant						
Final Withdrawal	9/16/1992	09999-RED	-1.48	-1.78	0.00	0.00
ROC and NOx balances discounted by 25%						
Final Withdrawal	9/16/1992	09999-PMR	0.00	0.00	-0.18	0.00
PM balance recalculated as PM10						
Final Withdrawal	9/8/1994	01119-TRN	-1.00	-1.00	0.00	0.00
Transfer to Rockwell Certificate No 1119						
Final Withdrawal	2/15/1995	01120-TRN	-3.43	0.00	0.00	0.00
Transfer to PTI Tech Certificate No 1120						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NO_x	PM₁₀	SO_x
Final	Withdrawal	7/18/1997	01078-TAC	0.00	-0.69	0.00	0.00
Implementation of revised Rule 74.9							
Final	Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.22	0.00
Transfer to Pacific Custom Materials Inc							
Final	Withdrawal	7/1/2001	00013-230	0.00	-3.66	0.00	0.00
Reliant Mandalay Unit 3 - 18 mo. Lease							
Final	Withdrawal	12/31/2002	00013-231	0.00	3.66	0.00	0.00
Return of ERC Lease from Reliant							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1079

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	0.72
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.01

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Fillmore NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit Removal of engines at Texaco Shiells Cyn	9/16/1992	00054-191	6.08	5.67	0.19	0.01
Final Withdrawal ROC and NOx balances discounted by 25%	9/16/1992	09999-RED	-1.52	-1.42	0.00	0.00
Final Withdrawal PM balance recalculated as PM10	9/16/1992	09999-PMR	0.00	0.00	-0.08	0.00
Final Withdrawal Implementation of revised Rule 74.9	7/18/1997	01079-TAC	0.00	-3.53	0.00	0.00
Final Withdrawal Culbert Lease Well No. 53	10/13/1997	00056-311	-0.18	0.00	0.00	0.00

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	10/13/1997	00056-292	-1.72	0.00	0.00	0.00
Increase Culbert Lease Throughput							
Final	Withdrawal	3/24/1998	01149-TRN	-1.88	0.00	0.00	0.00
Transfer to Nuevo Certificate No. 1149							
Final	Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.11	0.00
Transfer to Pacific Custom Materials Inc							
Final	Withdrawal	3/29/1999	01149-TRN	-0.78	0.00	0.00	0.00
Transfer to Nuevo Certificate No. 1149							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1080

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	0.17
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.00

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Fillmore NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	9/16/1992	00055-101	0.95	1.58	0.03	0.00
Removal of engine at Texaco Bardsdale						
Final Withdrawal	9/16/1992	09999-RED	-0.24	-0.40	0.00	0.00
ROC and NOx balances discounted by 25%						
Final Withdrawal	9/16/1992	09999-PMR	0.00	0.00	-0.01	0.00
PM balance recalculated as PM10						
Final Withdrawal	7/18/1997	01080-TAC	0.00	-1.01	0.00	0.00
Implementation of revised Rule 74.9						
Final Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.02	0.00
Transfer to Pacific Custom Materials Inc						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	9/17/2012	01223-TRN	-0.71	0.00	0.00	0.00
Transfer to Vintage ERC 1223							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1083

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	0.22
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.01

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Santa Paula NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit Removal of engine at Unocal Bridge	9/16/1992	00315-121	0.19	0.87	0.08	0.01
Final Withdrawal ROC and NOx balances discounted by 25%	9/16/1992	09999-RED	-0.05	-0.22	0.00	0.00
Final Withdrawal PM balance recalculated as PM10	9/16/1992	09999-PMR	0.00	0.00	-0.04	0.00
Final Withdrawal Permit existing paint/solvent/epoxy usag	7/20/1995	01340-121	-0.14	0.00	0.00	0.00
Final Withdrawal Increase natural gas consumption at 0146	10/17/1996	00146-141	0.00	-0.33	0.00	0.00

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NO _x	PM ₁₀	SO _x
Final	Withdrawal	1/21/1997	01136-TRN	0.00	-0.10	0.00	0.00
Transfer to Reichhold Certificate 1136							
Final	Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.04	0.00
Transfer to Pacific Custom Materials Inc							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1085

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	0.42
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.00

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Fillmore NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	9/16/1992	00050-121	1.72	0.56	0.00	0.00
Electrify engines at T.B. Properties						
Final Withdrawal	9/16/1992	09999-RED	-0.43	-0.14	0.00	0.00
ROC and NOx balances discounted by 25%						
Final Withdrawal	10/13/1997	00056-341	-0.03	0.00	0.00	0.00
Install New Crude Oil Storage Tank						
Final Withdrawal	3/29/1999	01149-TRN	-1.26	0.00	0.00	0.00
Transfer to Nuevo Certificate No. 1149						
Final Withdrawal	7/1/2001	00013-230	0.00	-0.28	0.00	0.00
Reliant Mandalay Unit 3 - 18 Mo. Lease						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	12/31/2002	00013-231	0.00	0.28	0.00	0.00
Return of ERC Lease from Reliant							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1091

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	6.41
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.03

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Ventura (Ojai) GA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	5/19/1993	00020-251	20.68	15.39	0.26	0.03
Electrify engines at Texaco Gas Plant 7						
Final Withdrawal	6/29/1995	00648-121	-0.01	-0.08	0.00	0.00
Existing portable compressor						
Final Withdrawal	7/18/1997	01091-TAC	0.00	-8.90	0.00	0.00
Implementation of revised Rule 74.9						
Final Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.26	0.00
Transfer to Pacific Custom Materials Inc						
Final Withdrawal	7/1/2001	00013-230	0.00	-6.41	0.00	0.00
Reliant Mandalay Unit 3 -18 mo. Lease						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	12/31/2002	00013-231	0.00	6.41	0.00	0.00
Return of ERC Lease from Reliant							
Final	Withdrawal	9/17/2012	01224-TRN	-20.67	0.00	0.00	0.00
Transfer to Vintage ERC 1224							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1092

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	23.24
Particulate Matter (PM10)	0.22
Sulfur Oxides	0.03

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Camarillo NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	5/19/1993	00001-121	3.14	111.12	0.22	0.03
Electrify Engines at P.Valley Water Dist						
Final Withdrawal	11/10/1993	01101-TRN	0.00	-15.00	0.00	0.00
Transfer to Amgen Certificate No. 1101						
Final Withdrawal	2/16/1994	01106-TRN	0.00	-9.63	0.00	0.00
Transfer to Dames & Moore Cert. No. 1106						
Final Withdrawal	8/11/1994	01118-TRN	-2.20	0.00	0.00	0.00
Transfer to Unocal Certificate No. 1118						
Final Withdrawal	3/28/1995	01122-TRN	-0.94	0.00	0.00	0.00
Transfer to PTI Tech Certificate No 1122						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	1/31/1996	01207-131	0.00	-0.10	0.00	0.00
Increase incinerator rating							
Final	Withdrawal	5/19/1997	01494-151	0.00	-6.98	0.00	0.00
Turbine Fuel Increase - Rule 74.23 Compl							
Final	Withdrawal	5/19/1997	01494-151	0.00	-1.02	0.00	0.00
Turbine Fuel Increase - Rule 74.23 Compl							
Final	Withdrawal	5/20/1997	01140-TRN	0.00	-0.15	0.00	0.00
Transfer to US Navy Certificate No. 1140							
Final	Withdrawal	3/22/2000	00232-311	0.00	-17.00	0.00	0.00
1 Year Lease to Boeing Fuel Tank Project							
Final	Withdrawal	10/5/2000	01266-151	0.00	-18.14	0.00	0.00
1 Year Lease to Manson Construction Co.							
Final	Withdrawal	8/28/2001	00232-331	0.00	-2.10	0.00	0.00
1 Year Lease - Boeing H2 Storage Project							
Final	Withdrawal	8/28/2001	00232-331	0.00	17.00	0.00	0.00
Return of ERC Lease - Boeing Fuel Tank							
Final	Withdrawal	5/7/2002	01381-281	0.00	-50.00	0.00	0.00
1 Year Lease - Amgen Backup Generators							
Final	Withdrawal	6/27/2002	01381-281	0.00	50.00	0.00	0.00
Return of ERC Lease - Amgen Backup Gens.							
Final	Withdrawal	6/27/2002	01381-321	0.00	-10.00	0.00	0.00
2 Year Lease - Amgen Backup Generators							
Final	Withdrawal	7/8/2002	01266-161	0.00	18.14	0.00	0.00
Return of ERC Lease-Manson Construction							
Final	Withdrawal	3/2/2004	00232-331	0.00	2.10	0.00	0.00
Return of ERC Lease - Boeing H2 Storage							
Final	Withdrawal	3/21/2005	01381-321	0.00	10.00	0.00	0.00
Return of ERC lease - Amgen Backup Gens.							
Final	Withdrawal	9/19/2012	01229-TRN	0.00	-55.00	0.00	0.00
Transfer to Vintage ERC No. 1229							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1094

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	5.57
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.02

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Ojai NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	5/19/1993	00004-141	5.47	5.77	0.13	0.02
Replace engines at Ojai Fee Lease w/elec						
Final Withdrawal	7/18/1997	01094-TAC	0.00	-0.20	0.00	0.00
Implementation of revised Rule 74.9						
Final Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.13	0.00
Transfer to Pacific Custom Materials Inc						
Final Withdrawal	12/13/1999	07113-121	-4.40	0.00	0.00	0.00
Increase Usage - 1 Yr Lease to Fluid Ink						
Final Withdrawal	1/31/2001	07113-131	4.40	0.00	0.00	0.00
Return of ERC Lease From Fluid Ink						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	7/1/2001	00013-230	-0.74	-5.57	0.00	0.00
Mandalay Unit 3 - 18 month lease							
Final	Withdrawal	12/31/2002	00013-231	0.74	-5.57	0.00	0.00
Return of ERC Lease from Reliant							
Final	Withdrawal	9/17/2012	01225-TRN	-5.47	0.00	0.00	0.00
Transfer to Vintage ERC 1225							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1097

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	4.97
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.03

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: Ventura (Ojai) NGA

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	2/24/1994	00008-331	18.30	19.46	0.24	0.03
Electrify Engines at Conoco Grubb Lease						
Final Withdrawal	7/18/1997	01097-TAC	-3.93	-14.49	0.00	0.00
Implementation of revised Rule 74.9						
Final Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.24	0.00
Transfer to Pacific Custom Materials Inc						
Final Withdrawal	1/31/2001	07113-131	-7.70	0.00	0.00	0.00
Increase Usage - 1 Yr Lease to Fluid Ink						
Final Withdrawal	3/2/2004	07113-141	7.70	0.00	0.00	0.00
Return of ERC Lease - Fluid Ink						

Transaction History (In Tons per Year):

Action		Date	Application	ROC	NOx	PM10	SOx
Final	Withdrawal	8/31/2011	01217-TRN	-14.37	0.00	0.00	0.00
Transfer to Vintage Production ERC 1217							

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1104

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	2.08
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.01

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: North Zone

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit SCE Mitigation-replace IC engs. w/electr	2/27/1996	00370-141	3.90	2.70	0.03	0.01
Final Withdrawal Implementation of revised Rule 74.9	7/18/1997	01104-TAC	0.00	-0.04	0.00	0.00
Final Withdrawal Transfer to Pacific Custom Materials Inc	6/1/1998	01151-TRN	0.00	0.00	-0.03	0.00
Final Withdrawal Transfer to Boeing Certificate No. 1163	6/4/2001	01163-TRN	0.00	-0.58	0.00	0.00
Final Withdrawal Transfer to Vintage ERC No. 1226	9/17/2012	01226-TRN	-3.90	0.00	0.00	0.00

CERTIFICATE OF EMISSION REDUCTION CREDITS

Certificate Number 1107

This Certificate Has Been Issued To The Following Company:

Southern California Edison Co.
2244 Walnut Grove Ave. Quad 1C
Rosemead, CA 91770

Emission Reduction Credit Balance (In Tons Per Year):

Reactive Organic Compounds	0.00
Nitrogen Oxides	3.20
Particulate Matter (PM10)	0.00
Sulfur Oxides	0.00

ERC Profile: Jan-Mar: 25% Apr-Jun: 25% Jul-Sep: 25% Oct-Dec: 25%

ERC Location: North Zone

Use of This Emission Reduction Credit Is Subject To The Following Limitations:

There are no limitations on the use of these emission reduction credits.

For:

Terri Thomas, Supervisor
Engineering Division

Michael Villegas
Air Pollution Control Officer

Transaction History (In Tons per Year):

Action	Date	Application	ROC	NOx	PM10	SOx
Final Deposit	2/26/1996	00366-241	3.96	3.49	0.04	0.00
SCE Mitigation-replace IC engs. w/electr						
Final Withdrawal	7/18/1997	01107-TAC	0.00	-0.29	0.00	0.00
Implementation of revised Rule 74.9						
Final Withdrawal	6/1/1998	01151-TRN	0.00	0.00	-0.04	0.00
Transfer to Pacific Custom Materials Inc						
Final Withdrawal	9/19/2012	01227-TRN	-3.96	0.00	0.00	0.00
Transfer to Vintage ERC No. 1227						

Appendix F

ERC Profile Check

Year	equipment	January	February	March	April	May	June	July	August	September	October	November	December	Total
2010	Unit 1	4.8	23.7	0	0.4	0	0.7	83.8	106.5	19.7	34.6	14.7	25.4	314.3
	Quarterly	9.1%				0.3%			66.8%			23.8%		100.0%
	Unit 2	77.3	23.1	0.6	0	0	0.9	178.7	127.4	59.1	73.6	22.6	24.4	587.7
	Quarterly	17.2%				0.2%			62.1%			20.5%		100.0%
	avg both units	13%				0%			64%			22%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	13%				0%			25%			22%		61%

←Profile Check

2011	Unit 1	82.5	0	0	6.2	0	53.6	91	50.1	50.2	0	0.6	0	334.2
	Quarterly	24.7%				17.9%			57.2%			0.2%		100.0%
	Unit 2	100.9	4.8	0	74.7	110	19	0	53.1	67	29	35.3	13.9	507.7
	Quarterly	20.8%				40.1%			23.7%			15.4%		100.0%
	avg both units	23%				29%			40%			8%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	23%				25%			25%			8%		80.5%

←Profile Check

2012	Unit 1	49	22.3	0.5	0	83.9	49.9	155.9	387.5	79.1	106.7	143.7	61.7	1140.2
	Quarterly	6.3%				11.7%			54.6%			27.4%		100.0%
	Unit 2	0.3	0	0	16.6	106.5	74.1	86.1	380.2	269.9	101.7	89.1	42.1	1166.6
	Quarterly	0.0%				16.9%			63.1%			20.0%		100.0%
	avg both units	3%				14%			59%			24%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	3%				14%			25%			24%		66.1%

←Profile Check

2013	Unit 1	143.6	0.6	0	0	127	125.4	122.7	46.8	71.5	48.8	191.9	184.8	1063.1
	Quarterly	13.6%				23.7%			22.7%			40.0%		100.0%
	Unit 2	104.4	14.6	201.6	141.5	178.1	151.9	97.6	67.1	86.1	37.8	158.5	189.8	1429
	Quarterly	22.4%				33.0%			17.6%			27.0%		100.0%
	avg both units	18%				28%			20%			34%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	18%				25%			20%			25%		88.1%

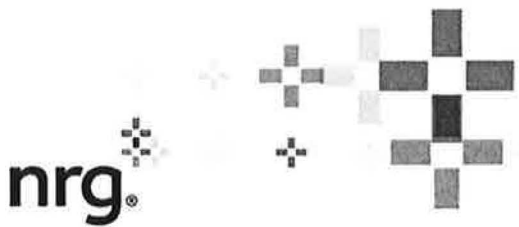
←Profile Check

2014	Unit 1	89	19.7	6	60.8	37.9	9.4	25.8	41.4	70.3	191.9	86.7	108.3	747.2
	Quarterly	15.4%				14.5%			18.4%			51.8%		100.0%
	Unit 2	143.8	79.6	3.4	130.7	41.6	9.1	47.1	50.3	40	183	42.6	57.6	828.8
	Quarterly	27.4%				21.9%			16.6%			34.2%		100.0%
	avg both units	21%				18%			17%			43%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	21%				18%			17%			25%		82.0%

←Profile Check

2010-2014	Unit 1	368.9	66.3	6.5	67.4	248.8	239	479.2	632.3	290.8	382	437.6	380.2	3599
	Quarterly	12.3%				15.4%			39.0%			33.3%		100.0%
	Unit 2	426.7	122.1	205.6	363.5	436.2	255	409.5	678.1	522.1	425.1	348.1	327.8	4519.8
	Quarterly	16.7%				23.3%			35.6%			24.4%		100.0%
	avg both units	14%				19%			37%			29%		100.0%
	ERC's	25%				25%			25%			25%		100%
	Lower value	14%				19%			25%			25%		83.9%

←Profile Check



NRG Energy Center Oxnard LLC

5790 Fleet Street, Suite 200
Carlsbad, CA 92008
Phone: 760-710-2156
Fax: 760-710-2158

March 29, 2016

Kerby E. Zozula
Manager, Engineering Division
Ventura County Air Pollution Control District
669 County Square Drive, 2nd Floor
Ventura, CA 93003

Subject: Application for an Authority to Construct/Determination of Compliance for
the Proposed Puente Power Project (ATC No. 00013-370)

Dear Mr. Zozula:

The Puente Power Project (P3 or project) Application for an Authority to Construct (ATC)/Determination of Compliance (DOC) was submitted to the Ventura County Air Pollution Control District (VCAPCD) on March 19, 2015, and was accepted as complete on May 28, 2015. The project includes the installation of a new simple-cycle GE 7HA.01 natural gas fired combustion turbine generator (CTG). As discussed in the ATC/DOC application package, the P3 triggers the VCAPCD New Source Review (NSR) emission offset requirements for NO_x emissions, and the Applicant has obtained a sufficient amount of NO_x emission reduction credits (ERCs) from Southern California Edison (SCE) to cover this NO_x ERC requirement.

VCAPCD Rule 26.6(F) requires that the quarterly operating profiles of the P3 be compared to the quarterly operating profiles of the SCE NO_x ERCs to ensure that the minimum 80% total required by Rule 26.6(F) is achieved. The P3 is expected to be a peaking facility that will be dispatched and used only when needed for grid support requirements. Therefore, it is difficult to predict the expected number of hours the plant will actually operate. Because the P3 will replace many of the grid support activities currently being provided by Mandalay Generating Station (MGS) Units 1 and 2, the Applicant believes the quarterly operating profiles for the P3 will be similar to quarterly profiles for MGS Units 1 and 2. In the enclosed summary tables, the Applicant sets the P3 quarterly operating profiles equal to the three-year average quarterly operating profiles for MGS Units 1 and 2. This analysis is based on the actual gross electrical output for MGS Units 1 and 2. As shown in these tables, the expected quarterly operating profiles for the P3 comply with the 80% total required by Rule 26.6(F).

If you have any questions or comments, please do not hesitate to contact me at (760) 710-2156.

Sincerely,

A handwritten signature in cursive script, appearing to read "George L. Plantka".

George L. Plantka, PE
Sr. Director, Regulatory Environmental Services
NRG Energy, Inc.

Enclosures (Tables 1 and 2)

cc: CEC Dockets
Leonard Scandura, SJVAPCD
Michael J. Carroll, Latham & Watkins
Anne Connell, AECOM

Table 1**Combined Gross Output (MW-hr) for MGS Units 1 and 2 (2013 to 2015)**

Quarter		Gross Output (MW-hr)	
2013-Q1	42,345		
2013-Q2	70,616		
2013-Q3	47,538		
2013-Q4	76,407		
Total	236,906		
2014-Q1	31,665		
2014-Q2	28,688		
2014-Q3	27,856		
2014-Q4	69,204		
Total	157,413		
2015-Q1	5,781		
2015-Q2	67,153		
2015-Q3	137,473		
2015-Q4	55,874		
Total	266,281		
3-Year Avg		Gross Output (MW-hr)	
Q1	26,597		
Q2	55,486		
Q3	70,956		
Q4	67,161		
Total	220,200		

Calendar Quarter	MGS Units 1 and 2 3-Year Average Combined Gross MW- hr Output	MGS Units 1 and 2 3-Year Average Quarterly Operating Profile	Expected P3 Average Quarterly Operating Profile	Quarterly Operating Profile of SCE NOx ERCs^a	VCAPCD Rule 26.6(F) Quarterly Operating Profile Adjustment^b	VCAPCD Rule 26.6(F) Minimum Threshold	P3 Complies with VCAPCD Rule 26.6(F)?
Q1	26,597	12.1%	12.1%	25.0%	12.1%		
Q2	55,486	25.2%	25.2%	25.0%	25.0%		
Q3	70,956	32.2%	32.2%	25.0%	25.0%		
Q4	67,161	30.5%	30.5%	25.0%	25.0%		
Total =	220,200	100.0%	100.0%	100.0%	87.1%	80%	Yes

Notes:

a. Based on SCE NOx ERCs quarterly operating profiles shown in <http://www.vcapcd.org/pubs/Engineering/permits2000/Forms/ERCReport.pdf>.

b. Per VCAPCD Rule 26.6(F), lower of quarterly operating profile for project vs. quarterly operating profile for ERC used for project.

APPENDIX G

Ambient Air Quality Analysis And Risk Management Review

For

PUENTE POWER PROJECT

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1. Purpose of this Document

This document serves as the Ambient Air Quality Analysis (AAQA) and Risk Management Review (RMR) for the proposed installation of a new H-Class simple cycle natural gas fired combustion turbine (CTG) and a new emergency diesel generator engine for the Puente Power Project. This document describes the modeling performed to satisfy the requirements of Ventura County Rule 26 (New Source Review) and Rule 51 (Nuisance).

2. Applicant

Project Site Location:

Puente Power Project at the Mandalay Generating Station
393 North Harbor Blvd.
Oxnard, CA 93035

Submitting Official:

George L. Piantka, PE
NRG Energy Center Oxnard LLC
5790 Fleet Street, Suite 200
Carlsbad, CA 92008

Phone: (760) 710-2156

Air Quality Consultant:

Tom Andrews
Sierra Research, Inc.
1801 J Street
Sacramento, CA 95811

Phone: (916) 444-6666

VCAPCD Permit Engineer:

Kerby E. Zozula
Manager Engineering Division
Ventura County APCD
669 County Square Drive
Ventura, CA 93003

Phone: (805) 645-1421

3. Project Location

The project is located at 393 North Harbor Blvd in Oxnard, California within the Ventura County Air Pollution Control District (VCAPCD). It is located in a rural setting along the coastline in Ventura County.



Figure 3-1 Project Location

4. Project Description

The Puente Power Project will consist of replacing the existing Mandalay Generating Station Natural Gas Fired Electric Utility Boiler (MGS Unit 2) (1,990 MMBtu/hr, 215 MW net) with a new natural gas fired GE H-Class simple-cycle combustion turbine generator (262 MW net nominal), replacing the existing diesel emergency generator engine with a new emergency generator engine, and shutting down the existing diesel emergency fire pump engine. The remainder of the facility will remain unchanged.

The new CTG will be fueled with pipeline quality natural gas and will be equipped with dry low-NOx combustion, selective catalytic reduction (SCR), and an oxidation catalyst. The operating schedule for the new unit will vary and may range from no operation during the winter months to potentially 24 hours of operation per day during the summer months. The maximum annual operation for the unit assumes a total of 200 hours of startups, 200 hours of shutdowns, and 1,750 hours of full load operation.

The new diesel emergency generator engine will be certified to meet non-road diesel engine EPA Tier 4 (final) standards. The new emergency diesel engine will only be operated for up to 200 hours per year for all types of operation.

5. Ventura County Rule 26 – New Source Review

Ambient Air Quality Standards (AAQS) are established to protect the public and the environment. An air quality standard defines the maximum amount of a pollutant that can be present in outdoor air without harm to public health, vegetation or wildlife. The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (40 CFR part 50) for pollutants considered harmful to public health and the environment. At present, EPA has set National Ambient Air Quality Standards for the following principal pollutants, which are called "criteria" pollutants:

- Ozone (O₃)
- Nitrogen Dioxide (NO₂)
- Sulfur Dioxide (SO₂)
- Respirable particulate matter having an aerodynamic diameter smaller than or equal to 10 microns (PM₁₀)
- Fine particulate matter having an aerodynamic diameter smaller than or equal to 2.5 microns (PM_{2.5})
- Carbon Monoxide (CO)
- Lead (Pb)

The National Ambient Air Quality Standards contain primary and secondary standards for each of the criteria pollutants. If a primary standard is exceeded, the public is considered at risk. If a secondary standard is exceeded, then crops, trees and buildings may be damaged. Air quality standards are based on a particular exposure period (averaging period) and concentration (average, maximum, or other statistical measure) during that period. A violation occurs if the observed concentration is greater than the standard during the specified averaging period.

The Clean Air Act also permits states to adopt additional or more protective air quality standards if needed. California law authorizes the Air Resources Board (ARB) to set ambient (outdoor) air pollution standards in consideration of public health, safety and welfare. California has set standards for certain pollutants, such as particulate matter and ozone, which are more protective of public health than respective federal standards. California has also set standards for some pollutants that are not addressed by federal standards, including the following:

- Visibility Reducing Particles
- Hydrogen Sulfide (H₂S)
- Vinyl Chloride

Both state and federal regulations require ambient air quality standards to be reviewed periodically, or whenever substantial new information becomes available.

Table 5-1. CAAQS/NAAQS Attainment Status for Ventura County

Pollutant	Attainment Status	
	Federal	State
Lead (Pb)	Attainment (Unclassified)	Attainment
Nitrogen Dioxide (NO ₂)	Attainment (Unclassified)	Attainment
Sulfur Dioxide (SO ₂)	Attainment (Unclassified)	Attainment
Carbon Monoxide (CO)	Attainment (Unclassified)	Attainment
Particulate Matter under 2.5 micrometers diameter (PM _{2.5})	Attainment	Attainment
Particulate matter under 10 micrometers diameter (PM ₁₀)	Attainment	Nonattainment
Ozone	1-hour	Nonattainment
	8-Hour	Nonattainment
Hydrogen Sulfide	N/A	Unclassified
Sulfates	N/A	Attainment
Visibility Reducing Particles	N/A	Unclassified
Vinyl Chloride	N/A	Attainment

VCAPCD Rule 26.2.C requires that:

The APCO shall deny an applicant an Authority to Construct for any new, replacement, modified or relocated emissions unit that would cause the violation of any ambient air quality standard or the violation of any ambient air increment as defined in 40 CFR 51.166(c). In making this determination the APCO shall take into account any offsets which were provided for the purpose of mitigating the emission increase.

In order to insure that this project will not cause or contribute to a violation of State or Federal air quality standards, an Ambient Air Quality Analysis (AAQA) must be performed.

VCAPCD has determined that AAQAs performed for the purpose of complying with New Source Review use EPA's preferred air dispersion model along with 5 years of meteorological data to perform the air dispersion modeling. Information necessary to perform dispersion modeling includes the coordinates of the sources of emissions and the plant/facility boundary. Also required are the stack/modeling parameters for all emissions sources involved in the project.

The AAQA performed for this project was conducted using a progressive approach where any failure of preliminary analyses necessitates advancing to more refined approaches.

5.1 Project Criteria Pollutant Emissions

5.1.1 Natural Gas Turbine

Emission rates for the gas turbine are determined by the unit's operating state. The following were considered for this evaluation:

- Commissioning. The period of time where the turbine is prepared for first operation, prior to the installation of the emissions control system. During this period NO_x and CO emissions are elevated.
- Startup. The period of time during which the turbine is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. During this period NO_x and CO emissions are elevated.
- Shutdown. The period of time during which the turbine is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. During this period NO_x and CO emissions are elevated.
- Normal Operations. The period of time during which the turbine is operating at optimal temperature and pressure. NO_x emissions reflect the application of dry, low-NO_x combustion and SCR. The CO emissions reflect the use of an oxidation catalyst.

For AAQA modeling the following worst-case scenarios were developed for the natural gas turbine emissions:

- Hourly emissions. Hourly emissions are from either startup or shutdown, whichever results in the worst case emissions for each pollutant.
- Annual emissions. Annual emissions are from 200 startups, 200 shutdowns, plus 1,750 hours of normal steady state operation.

5.1.2 Diesel Emergency Engine

For AAQA modeling the following worst-case scenarios were developed for the emergency diesel engine emissions:

- Hourly emissions. The emergency diesel engine will be operated for one hour at maximum load.
- Annual emissions. The emergency diesel engine will be operated a total of 200 hours per year for all purposes combined.

5.1.3 AAQA Emissions Summary

Applicable project emissions are shown in Table 5-2 (provided by the permit engineer). Note that PM_{2.5} emissions may be reported as both primary and

secondary PM_{2.5} emissions. If the project facility is a minor PM_{2.5} source, only primary (directly emitted) PM_{2.5} emissions are modeled. If the project facility is a major PM_{2.5} source, both the primary and secondary PM_{2.5} emissions are modeled. Since the project facility is a minor PM_{2.5} source, only primary PM_{2.5} emissions are required to be modeled.

Table 5-2. Emissions by Unit

Unit Description	Emissions (lbs)			
	SO _x	NO _x	CO	PM ₁₀ /PM _{2.5}
Commissioning – Maximum Hourly Emissions				
Natural Gas Turbine	5.5	246.3	1,973	10.1
Normal Operation – Maximum Hourly Emissions				
Natural Gas Turbine	5.5	143.2	412.2	10.1
Diesel Emergency Engine	0.008	0.86	4.48	0.03
Total	5.5	144.1	416.7	10.1
Normal Operation – Maximum Annual Emissions				
Natural Gas Turbine	11,820	65,900	108,840	21,360
Diesel Emergency Engine	2	172	896	6
Total	11,822	66,072	109,736	21,366

5.2 Refined Analysis

The VCAPCD modeled the impact of the proposed project on the NAAQS and/or CAAQS using EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51) for guidance. The VCAPCD used a progressive three level approach to perform the AAQA. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or SIL, the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO₂ standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses included the maximum air quality impacts during commissioning, startup, shutdown and normal operations of the turbine and normal operation of the emergency engine using the appropriate emissions during each averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

5.2.1 Model Selection

VCAPCD required that the following regulatory models be used to analyze air quality impacts:

Table 5-3. Summary of Preferred Models

Model Name	Model Purpose	Model Version
AERMOD	Air dispersion modeling	15181
AERMAP	Terrain processing	11103
AIRMET	Meteorological data processing	15181
AERSCREEN	Fumigation Modeling	15181

5.2.2 Background Ambient Air Quality

VCAPCD regulations require the air quality analysis to contain air quality monitoring data in the area for regulated pollutants for which there are NAAQS and/or CAAQS that may be affected by the source. For demonstrating compliance with the NAAQS and/or CAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, as determined by the VCAPCD, so that the total concentration accounts for all contributions to current air quality.

Ambient air concentrations of CO, ozone (O₃), NO₂, PM₁₀ and PM_{2.5} are recorded at monitoring stations throughout the South Central Coast Air Basin. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. Table 5-4 displays monitors within close proximity to the project, as well as the pollutants measured.

Table 5-4 Monitoring Stations in Close Proximity to the Project Site

Site Criteria	Monitoring Site			
	El Rio Rio Mesa School	Simi Valley Cochran St	Santa Barbara UCSB	Santa Barbara E Canyon Perdido
Site ID	06-111-3001	06-111-202	06-083-1020	06-083-0011
Distance from Project (km)	11	53	62	47
Direction from Project	NE	E	NW	NW
Urban/Rural	Rural	Urban	Rural	Urban
Land Use	Ag / Mixed	Residential	Undeveloped Mixed	Mixed
Pollutants Monitored				
Ozone (O ₃)	X	•		•
Nitrogen Dioxide (NO ₂)	X	•		•
Respirable Particulate (PM ₁₀)	X	•		•
Fine Particulate (PM _{2.5})	X	•		•
Carbon Monoxide (CO)				X
Sulfur Dioxide (SO ₂)			X	

X = site selected for pollutant indicated; "•" = pollutant monitored at site

The area immediately surrounding the project site can be characterized as rural with land use being predominantly farmland/undeveloped.

The monitoring station closest to the project site is the El Rio – Rio Mesa School #2 station in Oxnard, located 11 kilometers to the northeast. This station measures O₃, NO_x/NO₂, PM₁₀ and PM_{2.5}. This site is the most representative for these pollutants.

The Santa Barbara – UCSB station is located 62 kilometers to the northwest of the project site. This is the closest station to the project site that monitors SO_x, and was selected as having the most representative background value for this pollutant.

The Santa Barbara – Canyon Perdido station is located 47 kilometers to the northwest of the project site. This is the closest station to the project site that monitors CO, and was selected as having the most representative background value for this pollutant.

Table 5-5 below describes the maximum background concentrations, from the most recent available 3 year period of data collection, for which there are NAAQS and CAAQS that may be affected by the project's emissions.

Table 5-5 AAQS and Background Concentrations

Pollutant	Averaging Time	AAQS ($\mu\text{g}/\text{m}^3$)		Background Concentration ($\mu\text{g}/\text{m}^3$) ⁶
		California	National (Primary)	
Respirable Particulate Matter (PM ₁₀)	24 Hour	50	150	59
	Annual Arithmetic Mean	20	--	24
Fine Particulate Matter (PM _{2.5})	24 Hour ¹	--	35	21
	Annual Arithmetic Mean	12	15	9
Carbon Monoxide (CO)	1 Hour	23,000	40,000	4,580
	8 Hour	10,000	10,000	2,176
Nitrogen Dioxide (NO ₂)	1 Hour Max	339	---	169
	1 Hour 98 th Percentile ²	---	188	70
	Annual Arithmetic Mean	57	100	14
Sulfur Dioxide (SO ₂) ⁴	1 Hour Max	655	---	13
	1 Hour 99 th Percentile ³	---	196	11
	3 Hour ⁵	---	1,300	11
	24 Hour	105	365	5
	Annual Arithmetic Mean	--	79	3

¹ The PM_{2.5} 24-hr value is the 98th percentile averaged over three years.

² The 1-hr value as the 98th percentile averaged over three years.

³ The 1-hr value as the 99th percentile averaged over three years.

⁴ The SO₂ annual standard is replaced by the more stringent SO₂ 1-hour standard.

⁵ No primary standard exist for SO₂ 3-hour standard. Value used is for the secondary standard.

⁶ Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

5.2.3 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

- via elevation within AERMOD to assess plume interaction with the ground;
- via a choice of rural versus urban algorithm within AERMOD; and
- via specific values of AERMET parameters that affect turbulence and dispersion. This aspect will be discussed in more detail in Section 5.2.4, Meteorological Inputs.

5.2.3.1 Elevation

Terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data were used at a horizontal resolution of 30 meters, for receptor heights in AERMOD, which uses them to assess plume distance

from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

Table 5-6. Unit Location and Elevation Summary

Unit Description	Location			Elevation (m)
	UTM Zone	UTMN (m)	UTME (m)	
Natural Gas Turbine	11	3787499	292538	4.41
Diesel Emergency Engine	11	3787495	292540	4.42

5.2.3.2 Urban/Rural Classification

The classification of a site as urban or rural can be based on the Auer method specified in the EPA document Guideline on Air Quality Models (40 CFR Part 51, Appendix W). From the Auer's method, areas typically defined as Rural include:

- Residences with grass lawns and trees
- Large estates
- Metropolitan parks and golf courses
- Agricultural areas
- Undeveloped land
- Water surfaces

Auer defines an area as urban if it has less than 35% vegetation coverage or the area falls into one of the following use types:

Table 5-7. Land Use in Urban Classifications

Type	Use and Structures	Vegetation
I1	Heavy industrial	Less than 5%
I2	Light/moderate industrial	Less than 5%
C1	Commercial	Less than 15%
R2	Dense single / multi-family	Less than 30%
R3	Multi-family, two-story	Less than 35%

To determine if an area should be classified as urban or rural, evaluate land use within a 3 km radius from the center of the emissions source. If land use types I1, I2, C1, R2, and R3 account for 50 % or more of the area within 3 km, then the area is classified as urban, otherwise the area is classified as Rural. For this project, it was determined that the source's land use classification is rural.

5.2.4 Meteorological Inputs

5.2.4.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. In order to select a meteorological site, the VCAPCD did a qualitative comparison of the following factors from EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (Document EPA-454/R-99-005) recommended for consideration for siting:

- Proximity.
- Height of measurement.
- Aspects of the site's surface that affect turbulence and dispersion.

Table 5-8 provides the characteristics of the meteorological sites that are in close proximity to the project area, the type of data collected at each site, the met data processing parameters, and identifies the site selected.

Table 5-8. Surface Met Sites Near the Project Site

Site Criteria	Surface Met Sites			
	Oxnard Airport	Point Mugu NAS	Camarillo Airport	Santa Barbara Municipal Airport
Distance from Project (km)	4	16	15	60
Elevation	11	4	24	3
Direction from Project	E	SE	E	NW
Urban/Rural	Rural	Rural	Rural	Rural
Land Use	Ag/ Residential	Undeveloped Mixed	Ag/ Mixed	Mixed
Met Type	Station	Station	Station	Station
Station WBAN ID	93110	93111	23136	23190
Data Type	NCDC	NCDC	NCDC	NCDC
Years Available	2010-2014	2010-2014	2010-2014	2010-2014
U* Adjustment Applied	Yes	---	---	---
Site Selected	X			

¹Met data was processed per the VCAPCD's meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). Lakes' Land Cover Data Tool was used to update National Land Cover Data (NLCD) used by AERSURFACE.

The VCAPCD believes that the chosen surface meteorological data is the most representative for the proposed project analysis for the following reasons:

- The project site and the meteorological site are in close proximity to each other.
- The land use and the location with respect to near-field terrain features are similar between both the selected surface meteorological site and the project site.

- Both locations are at approximately the same elevation.
- There are no significant terrain features separating the surface meteorological site from the project site that would cause significant differences in wind or temperature conditions between these respective areas.



Figure 5-1 Oxnard Airport Met Site

5.2.4.1.1 Adjusted U^* Option

The adjusted U^* option in AERMET is focused on improving model performance during periods of stable/low-wind conditions. In making its determination the District reviewed the follow information:

- Information provided by EPA in the addendum of the *User's Guide for the AMS/EPA Regulatory Model – AERMOD* (EPA-454/B-03-001, September 2004) provided with AERMOD version 15181 indicates that model

performance is improved when using the adjusted U* option for a variety of sources and conditions.

- Discussion with EPA during the modeling updates for AERMOD version 15181.
- Discussion with other regulatory agencies involved with dispersion modeling.
- In an EPA presentation given during the 11th Modeling Conference titled *Proposed Updates to AERMOD Modeling System*, EPA stated that they have proposed in a Notice of Proposed Rule Making (NPRM) that the ADJ_U* option be listed in Appendix W of 40 CFR Part 51 as a regulatory option for AERMOD and AERMET.
- EPA has issued several recent concurrence memoranda for the use of the Adjusted U* option in projects subject to their review. On April 29, 2016 they approved its use for the Schiller Station energy generating facility. This project involved a tall stack located near complex terrain, where high modeled concentrations are likely to occur under low wind, stable conditions.

The District has concluded that there is significant evidence showing that the use of the Adjusted U* option improves AERMOD modeling performance. Therefore the District will allow the use of the Adjusted U* option in AERMET meteorological data and the AERMOD beta Adjusted U* option for permitting actions that are not EPA Prevention of Significant Deterioration (PSD) projects (as this is not a PSD project).

5.2.4.2 Upper Air Data

The Point Mugu NAS upper air met site is closest to the project site, but data completeness was not acceptable. Therefore, the VCAPCD selected upper air data from Vandenberg Air Force Base as the most representative upper air site available that had acceptable data completeness.

Table 5-9. Upper Air Met Sites Near the Project Site

Site Criteria	Vandenberg AFB	Point Mugu NAS
Distance from Project (km)	135	16
Direction from Project	NW	SE
Station WBAN ID	93214	93111
Years Available	2010-2014	2010-2014
Site Selected	X	

5.2.5 Receptor Grid

Receptors in the model are geographic locations at which the model estimates concentrations. Receptors were placed such that they have good area coverage and so that the maximum model concentrations can be found. At greater distances from the emissions source, spacing between receptors may be greater

since concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project boundary.

The VCAPCD used a Cartesian coordinate receptor grid to provide adequate spatial coverage surrounding the project area, to identify the extent of significant impacts, and to identify the maximum impact location. In the analyses, the VCAPCD used a grid with 25 meter spacing telescoping from the facility fence line to 250 meter spacing out to a distance of 20 km.

After a preliminary modeling run was completed, subgrids of varying sizes, with 25 meter spacing were placed at the points of maximum impact for each averaging period in order refine their impact values and locations.

5.2.6 Source Parameters

Screening modeling was performed to select worst-case CTG operating modes for each pollutant and averaging period. The modeling used emissions data based on an ISO temperature (59°F), average summer temperature (78°F), maximum summer temperature (82°F), and minimum temperature (39°F), and at nominal minimum and maximum CTG operating load points of 30 percent and 100 percent (percent loads based on gross MW output levels).

Table 5-10. Turbine Stack Parameter Screening Scenarios

Scenario	Ambient Temp. (°F)	Stack Exit Vel. (m/s)	Emissions (lbs/hr)			
			NO _x	CO	PM ₁₀ /PM _{2.5}	SO _x
Winter/Maximum	38.9	47.18	23.11	22.51	10.10	5.41
Winter/Minimum	38.9	25.69	9.67	9.42	10.10	2.27
ISO/Maximum	59.0	47.95	22.90	22.31	10.10	5.37
ISO/Minimum	59.0	25.60	9.47	9.22	10.10	2.23
Summer Avg. Temp./Maximum w/ Cooling	77.8	47.79	22.51	21.93	10.10	5.29
Summer Avg. Temp./Maximum w/o Cooling	77.8	46.57	21.71	21.15	10.10	5.09
Summer Avg. Temp./Minimum	77.8	26.43	9.79	9.54	10.10	2.30
Summer High Temp./Maximum w/ Cooling	82.0	48.01	22.64	22.06	10.10	5.31
Summer High Temp./Maximum w/o Cooling	82.0	46.57	21.40	20.85	10.10	5.02
Summer High Temp./Minimum	82.0	26.66	9.87	9.61	10.10	2.32

Modeling was performed to obtain maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentrations of NO_x, CO, SO_x, and PM₁₀/PM_{2.5}. After

evaluating modeled concentrations of each pollutant for each year in the five-year meteorological data set, it was determined that the “Winter/Maximum” parameters produced the highest impacts for NO_x, CO and SO_x, and the “ISO/Minimum” parameters produced the highest impacts for PM₁₀/PM_{2.5}. Therefore, further refined modeling was performed using the source parameters in the tables below to conservatively estimate the project’s impacts.

Table 5-11. Point Source Parameters

Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)
Natural Gas Turbine				
- Winter/Maximum ¹	57.3	755	47.2	6.706
- ISO Minimum ²	57.3	755	25.6	6.706
Diesel Emergency Engine	21.3	957	82.4	0.152

¹Winter/Maximum parameters selected as producing the highest impacts for NO_x, CO and SO_x

²ISO/Minimum parameters selected as producing the highest impacts for PM₁₀/PM_{2.5}.

5.2.6.1 Good Engineering Practice (GEP) Analysis

The VCAPCD performed a Good Engineering Practice (GEP) stack height analysis, to ensure that:

- downwash is properly considered in the modeling, and
- stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks.

The GEP analysis was performed with EPA’s BPIP Prime (Building Profile Input Program) software, which uses building dimensions and stack heights as inputs.

There were not any stacks present that exceeded GEP stack height of 65 meters. Therefore, actual stack heights were used to model emissions.



Figure 5-2. Onsite Structures (Blue Objects)

5.2.7 Level 1 AAQA

Assessment begins with the Level 1 approach, and only proceeds to the next level if necessary. In a Level 1 AAQA analysis, for each averaging period, the maximum modeled concentration for each source and receptor combination is summed to produce a worst-case concentration. The sum of the maximum modeled concentration and maximum monitor value is compared to the national and state AAQS to determine whether or not an exceedance would be expected to occur. If an exceedance does occur, the maximum modeled concentrations are compared to their SILs to determine whether they exceed their *de minimus* value. If emissions of a pollutant are expected to cause an exceedance of both the standard and SIL, a more refined approach is required.

5.2.7.1 Level 1 NO₂ Modeling

While the new 1-hour NO₂ NAAQS is defined relative to ambient concentrations of NO₂, the majority of NO_x emissions from stationary sources are in the form of nitric oxide (NO) rather than NO₂. Appendix W notes that the impact of an individual source on ambient NO₂ depends in part “on the chemical environment into which the source’s plume is to be emitted” (see Appendix W, Section 5.1.j). Because of the role NO_x chemistry plays in determining ambient impact levels of NO₂ based on modeled NO_x emissions, Section 5.2.4 of Appendix W recommends a three-tiered screening approach for NO₂ modeling. Later guidance documents issued by EPA expand on this approach. In a Level 1 AAQA it is assumed that there is a full conversion of NO to NO₂. A summary of the Level 1 AAQA results for turbine commissioning and

startup/shutdown/normal operation of the turbine plus operation of the emergency engine are provided in the following tables:

Table 5-12 Level 1 AAQA Results: Turbine Commissioning (Using Adjusted U* Option)

AAQS Pollutant & Averaging Time ¹	Modeled Impacts (µg/m ³)	Back-ground (µg/m ³) ³	Total (µg/m ³)	AAQS (µg/m ³)		Significant Impact Level (SIL, µg/m ³)	Project Impact Significant? ⁴	
				National	State		AAQS	SIL
CO, 1-hour	209.8	4,582	4,792	23,000	40,000	2000	No	No
CO, 8-hour	54.0	1,265	1,319	10,000	10,000	500	No	No
NO ₂ , 1-hour (CAAQS)	26.2	107	133	---	339	7.5	No	Yes
NO ₂ , 1-hour (NAAQS)	26.2	68	94	188	---	7.5	No	Yes
SO ₂ , 1-hour (CAAQS)	0.6	11	12	---	655	7.8	No	No
SO ₂ , 1-hour(NAAQS)	0.6	8	9	196	---	7.8	No	No
SO ₂ , 3-hour	0.3	11	11	1,300	---	25	No	No
SO ₂ , 24-hour	0.1	5	5	365	105	5	No	No
PM ₁₀ , 24-hour	0.1	57	57	150	50	5	Yes	No
PM _{2.5} , 24-hour	0.1	18	18	35	---	--- ²	No	---

¹Per applicant, the emergency engine will not operate during turbine commissioning. Only the new turbine was included in the evaluation.

²On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the Environmental Protection Agency (EPA) to vacate and remand to the EPA the portions of two Prevention of Significant Deterioration (PSD) PM_{2.5} rules (40 CFR 51.166 and 40 CFR 52.21) addressing the Significant Impact Levels (SILs) for PM_{2.5} so that the EPA could voluntarily correct an error in these provisions.

³Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

⁴If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

Table 5-13 Level 1 AAQA Results: Turbine Commissioning (Not Using Adjusted-U* Option)

AAQS Pollutant & Averaging Time ¹	Modeled Impacts (µg/m ³)	Back-ground (µg/m ³) ³	Total (µg/m ³)	AAQS (µg/m ³)		Significant Impact Level (SIL, µg/m ³)	Project Impact Significant? ⁴	
				National	State		AAQS	SIL
CO, 1-hour	429.2	4,582	5,011	23,000	40,000	2000	No	No
CO, 8-hour	115.3	1,265	1,380	10,000	10,000	500	No	No
NO ₂ , 1-hour (CAAQS)	53.6	107	161	---	339	7.5	No	Yes
NO ₂ , 1-hour (NAAQS)	53.6	68	122	188	---	7.5	No	Yes
SO ₂ , 1-hour (CAAQS)	1.2	11	13	---	655	7.8	No	No
SO ₂ , 1-hour(NAAQS)	1.2	8	9	196	---	7.8	No	No
SO ₂ , 3-hour	0.7	11	12	1,300	---	25	No	No
SO ₂ , 24-hour	0.1	5	5	365	105	5	No	No
PM ₁₀ , 24-hour	0.2	57	57	150	50	5	Yes	No
PM _{2.5} , 24-hour	0.2	18	18	35	---	--- ²	No	---

¹Per applicant, the emergency engine will not operate during turbine commissioning. Only the new turbine was included in the evaluation.

²On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the Environmental Protection Agency (EPA) to vacate and remand to the EPA the portions of two Prevention of Significant Deterioration (PSD) PM_{2.5} rules (40 CFR 51.166 and 40 CFR 52.21) addressing the Significant Impact Levels (SILs) for PM_{2.5} so that the EPA could voluntarily correct an error in these provisions.

³Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

⁴If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

As noted in the preceding tables (Table 5-12 and Table 5-13), emissions of CO, NO₂, SO₂ and PM_{2.5} during commissioning are not expected to cause an exceedance of any State or Federal ambient air quality standards. The 24-hour PM₁₀ background concentration in Ventura County exceeds the State ambient air quality standard. However, the 24-hour PM₁₀ emissions during commissioning are not expected to exceed the Federal SIL. Therefore, the project is not expected to contribute to an exceedance of the 24-hour PM₁₀ State or Federal standards.

Table 5-14 Level 1 AAQA Results: Turbine Startup/Shutdown/Normal Operations Plus Operation of the Emergency Engine (Using Adjusted U* Option)

AAQS Pollutant & Averaging Time	Modeled Impacts ($\mu\text{g}/\text{m}^3$)	Back-ground ($\mu\text{g}/\text{m}^3$) ²	Total ($\mu\text{g}/\text{m}^3$)	AAQS ($\mu\text{g}/\text{m}^3$)		Significant Impact Level (SIL, $\mu\text{g}/\text{m}^3$)	Project Impact Significant? ³	
				National	State		AAQS	SIL
CO, 1-hour	207.2	4,582	4,789	23,000	40,000	2000	No	No
CO, 8-hour	80.4	1,265	1,345	10,000	10,000	500	No	No
NO ₂ , 1-hour (CAAQS)	44.5	107	152	---	339	7.5	No	Yes
NO ₂ , 1-hour (NAAQS)	44.5	68	113	188	---	7.5	No	Yes
NO ₂ , annual (CAAQS)	0.0	13	13	100	57	1	No	No
SO ₂ , 1-hour (CAAQS)	0.7	11	12	---	655	7.8	No	No
SO ₂ , 1-hour (NAAQS)	0.7	8	9	196	---	7.8	No	No
SO ₂ , 3-hour	0.5	11	12	1,300	---	25	No	No
SO ₂ , 24-hour	0.1	5	5	365	105	5	No	No
SO ₂ , annual	0.0	3	3	79	--	1	No	No
PM ₁₀ , 24-hour	0.4	57	57	150	50	5	Yes	No
PM ₁₀ , annual	0.0	25	25	--	20	1	Yes	No
PM _{2.5} , 24-hour	0.4	18	18	35	---	--- ¹	No	No
PM _{2.5} , annual	0.0	9	9	15	12	--- ¹	No	No

¹On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the Environmental Protection Agency (EPA) to vacate and remand to the EPA the portions of two Prevention of Significant Deterioration (PSD) PM_{2.5} rules (40 CFR 51.166 and 40 CFR 52.21) addressing the Significant Impact Levels (SILs) for PM_{2.5} so that the EPA could voluntarily correct an error in these provisions.

²Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

³If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

Table 5-15 Level 1 AAQA Results: Turbine Startup/Shutdown/Normal Operations Plus Operation of the Emergency Engine (Not Using Adjusted-U* Option)

AAQS Pollutant & Averaging Time	Modeled Impacts ($\mu\text{g}/\text{m}^3$)	Back-ground ($\mu\text{g}/\text{m}^3$) ²	Total ($\mu\text{g}/\text{m}^3$)	AAQS ($\mu\text{g}/\text{m}^3$)		Significant Impact Level (SIL, $\mu\text{g}/\text{m}^3$)	Project Impact Significant? ³	
				National	State		AAQS	SIL
CO, 1-hour	412.8	4,582	4,995	23,000	40,000	2000	No	No
CO, 8-hour	86.3	1,265	1,431	10,000	10,000	500	No	No
NO ₂ , 1-hour (CAAQS)	88.3	107	195	---	339	7.5	No	Yes
NO ₂ , 1-hour (NAAQS)	88.3	68	156	188	---	7.5	No	Yes
NO ₂ , annual (CAAQS)	0.0	13	13	100	57	1	No	No
SO ₂ , 1-hour (CAAQS)	0.7	11	12	---	655	7.8	No	No
SO ₂ , 1-hour (NAAQS)	0.7	8	9	196	---	7.8	No	No
SO ₂ , 3-hour	0.5	11	12	1,300	---	25	No	No
SO ₂ , 24-hour	0.1	5	5	365	105	5	No	No
SO ₂ , annual	0.0	3	3	79	--	1	No	No
PM ₁₀ , 24-hour	0.4	57	57	150	50	5	Yes	No
PM ₁₀ , annual	0.0	25	25	--	20	1	Yes	No
PM _{2.5} , 24-hour	0.4	18	18	35	---	--- ¹	No	No
PM _{2.5} , annual	0.0	9	9	15	12	--- ¹	No	No

¹On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the Environmental Protection Agency (EPA) to vacate and remand to the EPA the portions of two Prevention of Significant Deterioration (PSD) PM_{2.5} rules (40 CFR 51.166 and 40 CFR 52.21) addressing the Significant Impact Levels (SILs) for PM_{2.5} so that the EPA could voluntarily correct an error in these provisions.

²Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

³If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

As noted in the preceding tables (Table 5-14 and Table 5-15), emissions of CO, NO₂, SO₂, and PM_{2.5} during normal operations are not expected to cause an exceedance of any State or Federal ambient air quality standard. The 24-hour PM₁₀ background concentration in Ventura County exceeds the State ambient air quality standard, and the annual PM₁₀ background concentration in Ventura County exceeds the State ambient air quality standard. However, the 24-hour and annual PM₁₀ emissions during startup/shutdown/normal operations are not expected to exceed the Federal SILs. Therefore, the project is not expected to contribute to an exceedance of the 24-hour or annual PM₁₀ State or Federal standards.

5.2.8 Fumigation Modeling

Fumigation occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground-level when unstable air below the plume reaches plume

level. Fumigation can cause very high ground-level concentrations. Two types of fumigation were analyzed for this project:

1. **Inversion breakup fumigation**. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack and “fumigates” the air below.
2. **Shoreline fumigation**. Shoreline fumigation is a turbulent dispersion process where a plume, released from a tall stack within the stable (or neutral) onshore breeze, enters a growing thermal internal boundary layer that forms over land. The plume is subsequently mixed to the ground by the convective turbulence within the thermal internal boundary layer.

Currently, AERSCREEN is the only regulatory model approved by EPA for shoreline fumigation and inversion breakup modeling. AERSCREEN calculates fumigation due to inversion break-up and shoreline fumigation for point sources with release heights (above ground level) of 10 m or more. The fumigation equations for AERSCREEN are taken from SCREEN3. Surface files were generated with the following parameters using AERSURFACE and a geoTIFF file from the 2011 National Land Cover Database (NLCD2011):

- Center latitude: 34.207826
- Center longitude: -119.251759
- Datum: NAD83
- Study radius (km) for surface roughness: 1.0
- Airport: N
- Continuous snow cover: N
- Surface moisture: average
- Arid region: Y
- Month/season assignments: user-specified
- Late autumn after frost and harvest, or winter with no snow: 0
- Winter with continuous snow on ground: 0
- Transitional spring (partial green coverage, short annuals): 1, 2, 3, 4, 5, 6, 11, 12
- Midsummer with lush vegetation: 7, 8, 9, 10
- Autumn with unharvested cropland: 0
- Freq sect: monthly 3
 - Sector 1: 100-160
 - Sector 2: 160-330
 - Sector 3: 330-100

Meteorological data for AERSCREEN was then generated by MAKEMET using these surface files. Fumigation analysis was conducted for each of the screening scenarios previously presented in Table 5-10. Ambient air quality analysis results are presented in the table below.

Table 5-16 Level 1 AAQA Results: Fumigation

AAQS Pollutant & Averaging Time	Modeled Impacts ($\mu\text{g}/\text{m}^3$) ¹	Back-ground ($\mu\text{g}/\text{m}^3$) ²	Total ($\mu\text{g}/\text{m}^3$)	AAQS ($\mu\text{g}/\text{m}^3$)		Significant Impact Level (SIL, $\mu\text{g}/\text{m}^3$)	Project Impact Significant? ³	
				National	State		AAQS	SIL
CO, 1-hour	181.6	4,582	4,764	23,000	40,000	2000	No	No
CO, 8-hour	42.1	1,265	1,307	10,000	10,000	500	No	No
NO ₂ , 1-hour (CAAQS)	63.1	107	170	---	339	7.5	No	Yes
NO ₂ , 1-hour (NAAQS)	63.1	68	131	188	---	7.5	No	Yes
SO ₂ , 1-hour (CAAQS)	1.3	11	12	---	655	7.8	No	No
SO ₂ , 1-hour (NAAQS)	1.3	8	9	196	---	7.8	No	No
SO ₂ , 3-hour	0.8	11	12	1,300	---	25	No	No
SO ₂ , 24-hour	0.2	5	5	365	105	5	No	No
PM ₁₀ , 24-hour	0.4	57	57	150	50	5	Yes	No
PM _{2.5} , 24-hour	0.4	18	18	35	---	--- ¹	No	No

¹Fumigation modeled impact reported as the higher of the shoreline fumigation or inversion breakup fumigation concentrations.

²Background reported as the maximum design value for the most recent 3-year period for which information is available (2012-2014).

³If the project is expected to cause an exceedance of both the AAQS and SIL for any of the pollutant/averaging time categories, a more refined assessment would be required for the project as is explained in Section 5.2.7. As shown above, no impacts are above both the AAQS and the SIL, therefore no further analysis is needed.

As noted in the table above, emissions of CO, NO₂, SO₂, and PM_{2.5} under fumigation conditions are not expected to cause an exceedance of any State or Federal ambient air quality standard. The 24-hour PM₁₀ background concentrations in Ventura County exceed the State ambient air quality standard. However, the 24-hour PM₁₀ emissions under fumigation conditions are not expected to exceed the Federal SILs. Therefore, the project is not expected to contribute to an exceedance of the 24-hour or annual PM₁₀ State or Federal standards.

6. Ventura County APCD Rule 51 – Nuisance Risk Management Review

The purpose of VCAPCD Rule 51 is to protect the health and safety of the public. This rule prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. VCAPCD requires that for an increase in emissions or a change in mode or time of operation associated with a proposed new source or modification, VCAPCD shall perform an analysis to determine the possible impact to the nearest resident or worksite. An assessment shall be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the VCAPCD's significance threshold and;
- The project's prioritization score is less than the VCAPCD's significance threshold and;
- The facility's total prioritization score is less than the VCAPCD's significance threshold

Then, generally no further analysis is required.

The significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the threshold, a screening or a refined assessment is required using VCAPCD approved models including but not limited to VCAPCD screening assessment tools, EPA's AERMOD, and CARB's HARP2 program. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 2-5 km from the facility). Modeling should be performed in accordance with VCAPCD, OEHH, and EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W).

If a refined assessment is greater than one in a million but less than 10 in a million for carcinogenic impacts (cancer risk) and less than 1.0 for the acute and chronic Hazard Indices (non-carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For projects that exceed a cancer risk of 10 in one million or an acute or chronic hazard index of 1.0, the applicant must develop and implement a Health Risk Reduction Plan as explained in Section 6.7.1 of this document.

Carcinogenic impacts greater than 10 in a million, or acute or chronic hazard indices greater than 1.0 are considered significant and may not be permitted.

6.1 Toxic Emissions

Toxic emissions for the proposed natural gas turbine were calculated using hourly and annual rates of natural gas combustion calculated by the permit engineer and emission factors provided by the applicant. Toxic emission factors for the turbine were proposed by the applicant and compiled from two sources:

- US EPA's AP-42 Table 3.1-3 (4/00). Since the emission factors presented in AP-42 are uncontrolled, a 50% control efficiency was applied to account for the presence of the oxidation catalyst.
- The California Toxic Emission Factor (CATEF) database. Information from this database was used to supplement the toxic emissions profile by adding pollutants not included in AP-42's profile.

The turbine emission factors proposed are similar to those used for the Pio Pico Energy Center in San Diego.

Toxic emissions for the proposed diesel emergency engine were calculated as the mass of diesel particulate matter (DPM), which is considered equal to its PM₁₀ emissions.

Emissions unit process rates are summarized in the following table:

Table 6-1. Source Process Rates

Unit Description	Process Material	Process Units	Hourly Process Rate	Annual Process Rate
Natural Gas Turbine	Natural Gas	MMBtu	2,572	5,529,800
Diesel Emergency Engine	Diesel Particulate Matter	Hours of operation	1	200

Toxics emissions are summarized in the following table:

Table 6-2. Source Process Rates

Pollutant ID	Pollutant Name	Max. Hourly Emissions (lbs) ¹	Annual Emissions (lbs) ²	Emission Factor Origin
Natural Gas Turbine				
7664417	Ammonia	1.75E+01	3.52E+04	Permit Limit
115071	Propylene	7.79E+00	4.82E+03	CATEF ³
75070	Acetaldehyde	4.12E-01	2.55E+02	AP-42 ⁴
107028	Acrolein	6.61E-02	4.09E+01	AP-42
71432	Benzene	1.24E-01	7.65E+01	AP-42
106990	1,3-Butadiene	4.44E-03	2.74E+00	AP-42
100414	Ethylbenzene	3.30E-01	2.04E+02	AP-42
50000	Formaldehyde	9.27E+00	5.73E+03	CATEF ⁴
110543	Hexane	2.62E+00	1.62E+03	CATEF
91203	Naphthalene	1.35E-02	8.35E+00	AP-42
---	Total PAH's (listed individually below)	6.63E-03	4.10E+00	---
83329	Acenaphthene	1.92E-04	1.18E-01	CATEF
208968	Acenaphthylene	1.48E-04	9.17E-02	CATEF
120127	Anthracene	3.42E-04	2.12E-01	CATEF
56553	Benzo(a)anthracene	2.29E-04	1.41E-01	CATEF
50328	Benzo(a)pyrene	1.40E-04	8.66E-02	CATEF
192972	Benzo(e)pyrene	5.50E-06	3.40E-03	CATEF
205992	Benzo(b)fluoranthrene	1.14E-04	7.07E-02	CATEF
207089	Benzo(k)fluoranthrene	1.11E-04	6.88E-02	CATEF
191242	Benzo(g,h,i)perylene	1.38E-04	8.54E-02	CATEF
218019	Chrysene	2.55E-04	1.58E-01	CATEF
53703	Dibenz(a,h)anthracene	2.37E-04	1.47E-01	CATEF
206440	Fluoranthene	4.37E-04	2.70E-01	CATEF
86737	Fluorene	5.87E-04	3.63E-01	CATEF
193395	Indeno(1,2,3-cd)pyrene	2.37E-04	1.47E-01	CATEF
85018	Phenanthrene	3.17E-03	1.96E+00	CATEF
129000	Pyrene	2.80E-04	1.73E-01	CATEF
75569	Propylene oxide	2.99E-01	1.85E+02	AP-42
108883	Toluene	1.35E+00	8.35E+02	AP-42
1330207	Xylene	6.59E-01	4.08E+02	AP-42
Diesel Emergency Engine				
9901	Diesel particulate matter	3.00E-02	6.00E+00	Engine's EPA Certification

¹The maximum hourly emissions for the natural gas turbine represent a startup/shutdown scenario with a low catalyst control efficiency that results in an 8.01 time increase in the rate of toxic emissions. This rate of increase was calculated as the ratio of the worst case startup/shutdown hourly VOC emission rate to the normal operation hourly VOC emission rate.

²Annual emissions for the natural gas turbine represent 400 combined startup/shutdown hours and 1,750 normal operation hours.

³Toxic emission factors derived from the California Toxic Emission Factor (CATEF) database. The CATEF emission factors (mean values) were converted to from lb/mmcf to lb/mmBtu using the HHV of natural gas.

⁴Toxic emission factor derived from US EPA's AP-42 Table 3.1-3 (4/00). Since the emission factors presented in AP-42 are uncontrolled, a 50% control efficiency was applied to account for the presence of the oxidation catalyst.

The VCAPCD compared the turbine's hourly and annual toxic emissions calculated using the applicant's toxics profile to hourly and annual emissions calculated using the District's default profile for uncontrolled toxic emissions from natural gas-fired turbines (AP-42 Table 3.1-3 (4/00)). The District found that the proposed profile generated hourly and annual toxic emissions that resulted in cancer, chronic and acute risk values that were similar to those calculated from the default profile. Therefore, the District determined that the toxic emissions calculated using the applicant's proposed profile represented a conservative estimate and were acceptable for this project.

6.2 Prioritization

The prioritization methodology used by the VCAPCD was developed by the *Facility Prioritization Guidelines of the AB 2588 Risk Assessment Committee* of the California Air Pollution Control Officers Association (CAPCOA) in 1990. In December of 2014, CAPCOA changed the cancer normalization factor for the emissions and potency method from 1,700 to 7,700 to account for changes made by OEHHA to their risk assessment methodology.

The prioritization methodology has two basic methods that can be used to determine a source's potential impact on nearby receptors. The first is the "Emissions and Potency" method which relies on the quantity of a specific pollutant and the pollutant's specific potency (tendency to cause harm) in conjunction with the distance a source is from a receptor to calculate a score or potential for exposure.

The second method, "Dispersion Adjustment", is similar to the first method except that the stack height is also included as a parameter in the calculations to derive the prioritization score. Both prioritization methodologies look at three aspects of exposure 1) Acute short term non-carcinogenic risk [1-24 hours], 2) Chronic long term non-carcinogenic risk [24 hours to 1 year], and 3) Carcinogenic risk over a 70 year period.

For the purpose of this assessment the word carcinogenic refers to those compounds that have been identified by the Office of Environmental Health hazard Assessment (OEHHA) as having the potential of cause cancer.

Since the applicant determined that a refined health risk assessment was required in their assessment, a prioritization was not performed.

6.3 Screening and Refined Assessment

If modeling is required after implementing a screening technique, two modeling options may be available.

- The first option is a screening model that uses conservative modeling assumptions to estimate impacts, or it may be a spreadsheet that was derived from a screening/refined model using conservative assumptions.
- The second option is to use a refined model which will require more resources and time. This is due to the facility and source specific information required to perform a given run.

The determination of which option is used will mainly be based on the following:

- Is there a screening method available for the scenario under review?
- Is the conservative screening method acceptable to the reviewing agency?
- Is the meteorological data used to develop the screening method acceptable?
- Are the source parameters used in the screening method acceptable?

The VCAPCD does not have a screening method available for the sources included in this project. Therefore, a refined assessment was conducted.

6.4 Refined Assessment

The impact of the project was assessed in accordance with VCAPCD, OEHHA, and CARB guidance. The modeling analyses included the maximum air quality impacts during commissioning, startup, shutdown and normal operations using maximum hourly emissions for the acute hazard index (HI), annual emissions for the chronic HI, and annual emissions for the cancer risk.

6.4.1 Model Selection

The VCAPCD requires that the following regulatory models be used to analyze health impacts in the project area:

Table 6-3. Summary of Preferred Models

Model Name	Model Purpose	Model Version
AERMOD	Air dispersion modeling	15181
AERMAP	Terrain processing	11103
AIRMET	Meteorological data processing	13350
HARP2	Analysis of health impacts	16088

6.4.2 Land Characteristics

Land characteristics are used in the AERMOD modeling system in three ways:

- via elevation within AERMOD to assess plume interaction with the ground;
- via a choice of rural versus urban algorithm within AERMOD; and

- via specific values of AERMET parameters that affect turbulence and dispersion. This aspect applies to the meteorological inputs discussed in Section 6.4.3.

6.4.2.1 Elevation

Terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data were used at a horizontal resolution of 30 meters, for receptor heights in AERMOD, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83). The AERMOD, receptor elevations were interpolated among the NED nodes according to standard AERMAP procedure.

Table 6-4. Unit Location and Elevation Summary

Unit Description	Location			Elevation (m)
	UTM Zone	UTMN (m)	UTME (m)	
Natural Gas Turbine	11	3787499	292538	4.41
Diesel Emergency Engine	11	3787495	292540	4.42

6.4.2.2 Urban/Rural Classification

The classification of a site as urban or rural can be based on the Auer method specified in the EPA document Guideline on Air Quality Models (40 CFR Part 51, Appendix W). From the Auer's method, areas typically defined as Rural include:

- Residences with grass lawns and trees
- Large estates
- Metropolitan parks and golf courses
- Agricultural areas
- Undeveloped land
- Water surfaces

Auer defines an area as urban if it has less than 35% vegetation coverage or the area falls into one of the following use types:

Table 6-5. Land Use in Urban Classifications

Type	Use and Structures	Vegetation
I1	Heavy industrial	Less than 5%
I2	Light/moderate industrial	Less than 5%
C1	Commercial	Less than 15%
R2	Dense single / multi-family	Less than 30%
R3	Multi-family, two-story	Less than 35%

To determine if an area should be classified as urban or rural, evaluate land use within a 3 km radius from the center of the emissions source. If land use types I1, I2, C1, R2, and R3 account for 50 % or more of the area within the circle, then the area is classified as urban, otherwise the area is classified as Rural.

For this project, it was determined that the source's land use classification is rural.

6.4.3 Meteorological Inputs

6.4.3.1 Surface Data

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. In order to select a meteorological site, the VCAPCD did a qualitative comparison of the following factors from EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (Document EPA-454/R-99-005) recommended for consideration for siting:

- Proximity.
- Height of measurement.
- Aspects of the site's surface that affect turbulence and dispersion.

Table 6-6 provides the characteristics of the meteorological sites that are in close proximity to the project area, the type of data collected at each site, the met data processing parameters, and identifies the site selected.

Table 6-6. Surface Met Sites Near the Project Site

Site Criteria	Surface Met Sites			
	Oxnard Airport	Point Mugu NAS	Camarillo Airport	Santa Barbara Municipal Airport
Distance from Project (km)	4	16	15	60
Elevation	11	4	24	3
Direction from Project	E	SE	E	NW
Urban/Rural	Rural	Rural	Rural	Rural
Land Use	Ag/ Residential	Undeveloped Mixed	Ag/ Mixed	Mixed
Met Type	Station	Station	Station	Station
Station ID	93110	93111	23136	23190
Data Type	NCDC	NCDC	NCDC	NCDC
Years Available	2009-2013	2009-2013	2009-2013	2009-2013
U* Adjustment Applied	Yes	---	---	---
Site Selected	X			

¹Met data was processed per the SJVAPCD's meteorological data processing guidance (http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm#modeling_guidance). Lakes' Land Cover Data Tool was used to update National Land Cover Data (NLCD) used by AERSURFACE.

The VCAPCD believes that the chosen surface meteorological data is the most representative for the proposed project analysis for the following reasons

- The project site and the meteorological site are in close proximity to each other.
- The land use and the location with respect to near-field terrain features are similar between both the selected surface meteorological site and the project site.
- Both locations are at approximately the same elevation.
- There are no significant terrain features separating the surface meteorological site from the project site that would cause significant differences in wind or temperature conditions between these respective areas.



Figure 6-1 Oxnard Airport Met Site

6.4.3.1.1 Adjusted U^* Option

The adjusted U^* option in AERMET is focused on improving model performance during periods of stable/low-wind conditions. In making its determination the District reviewed the follow information:

- Information provided by EPA in the addendum of the *User's Guide for the AMS/EPA Regulatory Model – AERMOD* (EPA-454/B-03-001, September 2004) provided with AERMOD version 15181 indicates that model performance is improved when using the adjusted U^* option for a variety of sources and conditions.
- Discussion with EPA during the modeling updates for AERMOD version 15181.
- Discussion with other regulatory agencies involved with dispersion modeling.

- In an EPA presentation given during the 11th Modeling Conference titled *Proposed Updates to AERMOD Modeling System*, EPA stated that they have proposed in a Notice of Proposed Rule Making (NPRM) that the ADJ_U* option be listed in Appendix W of 40 CFR Part 51 as a regulatory option for AERMOD and AERMET.
- EPA has issued several recent concurrence memoranda for the use of the Adjusted U* option in projects subject to their review. On April 29, 2016 they approved its use for the Schiller Station energy generating facility. This project involved a tall stack located near complex terrain, where high modeled concentrations are likely to occur under low wind, stable conditions.

The District has concluded that there is significant evidence showing that the use of the Adjusted U* option improves AERMOD modeling performance. Therefore the District will allow the use of the Adjusted U* option in AERMET meteorological data and the AERMOD beta Adjusted U* option for permitting actions that are not EPA Prevention of Significant Deterioration (PSD) projects (as this is not a PSD project).

6.4.3.2 Upper Air Data

The Point Mugu NAS upper air met site is closest to the project site, but data completeness was not acceptable. Therefore, the VCAPCD selected upper air data from Vandenberg Air Force Base as the most representative upper air site available that had acceptable data completeness.

Table 6-7. Upper Air Met Sites Near the Project Site

Site Criteria	Vandenberg AFB	Point Mugu NAS
Distance from Project (km)	135	16
Direction from Project	NW	SE
Station WBAN ID	93214	93111
Years Available	2009-2013	2009-2013
Site Selected	X	

6.4.4 Sensitive Receptors

Sensitive receptors are defined as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large. Additionally, the VCAPCD includes in the definition of sensitive receptors locations occupied by groups of individuals that may be more susceptible than the general population to health risks from a chemical exposure and therefore include schools (public and private), day-care facilities, convalescent homes, parks, and hospitals.

The RMR approach treats all receptors as sensitive receptors. Long term health impacts (chronic and cancer) are evaluated for all sensitive receptors within the project area. In addition, short term health impacts (acute) are evaluated at all locations within the project area (beyond the facility fence line) at which an individual may be exposed for a period of one hour.

6.4.5 Source Parameters

Modeling was performed using the source parameters in the tables below to conservatively estimate the project's impacts.

Table 6-8. Point Source Parameters

Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)
Natural Gas Turbine	57.3	755	47.5	6.706
Diesel Emergency Engine	21.3	957	82.4	0.152

6.5 Risk Management Review (RMR)

Adverse health effects are expressed in terms of cancer or non-cancer health risks. Cancer risk is typically reported as “lifetime cancer risk,” which is the estimated maximum increase in the risk of developing cancer caused by long-term exposure to a pollutant identified as being a carcinogen by the OEHHA. The calculation of cancer risk conservatively assumes an individual is exposed continuously to the maximum pollutant concentrations 24 hours per day for 70 years. Although such continuous lifetime exposure to maximum Toxic Air Contaminants (TAC) levels is highly unlikely, the goal of the approach is to produce a conservative worst-case estimate of potential cancer risk.

Non-cancer risk is typically reported as a Hazard Index (HI). The HI is calculated for each target organ as a fraction of the maximum acceptable exposure level or REL for an individual pollutant. The REL is generally the level at (or below) which no adverse health effects are expected. The HI's are calculated for both short-term (acute) and long-term (chronic) exposures to non-carcinogenic substances by adding the ratios of predicted concentrations to RELs for all pollutants.

Both cancer and non-cancer risk estimates produced by the RMR represent incremental risks (i.e., risks due to the modeled sources only) and do not include potential health risks posed by existing background concentrations. The HARP model performs all of the necessary calculations to estimate the potential lifetime cancer risk, and the acute and chronic non-cancer HIs due to the project's TAC emissions. The following parameters were selected in the HARP model:

- Intake rate percentile

- OEHHA derived method
- Exposure duration
 - Resident: 70 years
 - Fraction time at home adjustment: disabled
 - Worker: 25 years
- Site parameters
 - Inhalation pathway: enabled
 - Drinking water pathway: disabled
 - Fish water pathway: enabled (resident)
 - Surface area: 532,525 m²
 - Volume: 1,772,649,000 kg
 - Volume changes per year: 1
 - Fraction fish consumed from contaminates source: 1
 - Beef/dairy (pasture) pathway: disabled
 - Home grown produce pathways: enabled (resident)
 - Pigs, chickens, and/or eggs pathways: disabled
 - Dermal pathway: enabled
 - Soil ingestion pathway: enabled
 - Mother's milk pathway: enabled (resident)
 - Deposition rate: 0.02 m/s

6.6 Risk Management Review Significance Thresholds

Project-related emissions are considered significant when the predicted increase in lifetime cancer risk exceeds 10 in 1 million (10×10^{-6}), and the non-carcinogenic acute and chronic hazard index exceeds a value of 1.0.

6.7 Risk Management Review Results

The locations of the maximally exposed receptors for each type of adverse health impact are presented in Table 6-9.

Table 6-9. RMR Project Level Maximally Exposed Receptors

Unit Description	Health Impact	Receptor Type	Receptor Location		
			UTM Zone	UTMN (m)	UTME (m)
Using Adjusted U* Option (Adj-U*)					
Natural Gas Turbine	Cancer	Resident ¹	11	3787509	296622
	Chronic	Worker	11	3787370	293874
	Acute	Grid	11	3800207	295714
Diesel Emergency Engine	Cancer	Resident	11	3787067	293443
	Chronic	Worker	11	3787350	293417
	Acute	--	---	---	---
Combined	Cancer	Resident	11	3787067	293443
	Chronic	Worker	11	3787370	293734
	Acute	Grid	11	3800207	295714
Not Using Adjusted U* Option					
Natural Gas Turbine	Cancer	Resident	11	3787509	296622
	Chronic	Worker	11	3787370	293874
	Acute	Grid	11	3799207	296464
Diesel Emergency Engine	Cancer	Resident	11	3787067	293443
	Chronic	Worker	11	3787350	293418
	Acute	--	11	--	--
Combined	Cancer	Resident	11	3787067	293443
	Chronic	Worker	11	3787370	293874
	Acute	Grid	11	3788207	296464

¹Resident refers to the Maximally Exposed Individual Resident (MEIR).

²Worker refers to the Maximally Exposed Individual (Offsite) Worker (MEIW)

The estimated cancer risk, and acute and chronic non-cancer hazard indexes for the project are summarized in Table 6-10.

Table 6-10 RMR Results

Unit Description	Cancer Risk	Hazard Index	
		Chronic	Acute
Using Adjusted U* Option (Adj-U*)			
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	2.08 x 10 ⁻²
Diesel Emergency Engine	5.37 x 10 ⁻⁸	1.66 x 10 ⁻⁵	---
Project Total	8.48 x 10 ⁻⁸	9.23 x 10 ⁻⁵	2.08 x 10 ⁻²
Not Using Adjusted U* Option			
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	4.19 x 10 ⁻²
Diesel Emergency Engine	4.22 x 10 ⁻⁸	1.59 x 10 ⁻⁵	--
Project Total	7.32 x 10 ⁻⁸	9.12 x 10 ⁻⁵	4.19 x 10 ⁻²

The acute and chronic indices are below 0.5 and the cancer risk associated with the project is less than 1 in a million. In accordance with the attached VCAPCD policy regarding Air Toxic Review of Permit Applications (revised 7/10/02), the project is approved as proposed.

6.7.1 Health Risk Reduction Plan

Per the attached VCAPCD policy regarding Air Toxic Review of Permit Applications (revised 7/10/02), if the health risk assessment indicates that the carcinogenic risk is greater than 1 in a million, or that the acute or chronic hazard indices are greater than 1, District staff will work with the applicant to reduce the risk to an acceptable level. If after working with the applicant to reduce the risk, the health risk assessment still indicates that the additional carcinogenic risk is greater than 10 in a million, or with acute or chronic hazard indices greater than 1, permit conditions will be placed on the permit requiring the applicant to develop and implement a Health Risk Reduction Plan.

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the each new emissions unit is less than 1.0 in a million. Therefore, a Health Risk Reduction Plan will not be required for this project.

6.7.2 Rule 51 Permit Conditions

To ensure that human health risks will not exceed VCAPCD allowable levels; the following permit conditions shall be included for:

New Turbine - CTG

- The CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas.
- The CTG shall be operated with an oxidation catalyst and a selective catalytic reduction (SCR) system.

New Emergency Engine

- The PM₁₀ emissions rate shall not exceed the EPA Tier 4-Final Standard of 0.02 g/bhp-hr based on U.S. EPA certification.
- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. A flapper type rain cap that is open while the engine is operating may be used.
- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight shall be used.

7. Report Summary

7.1 Ventura County Rule 26 - New Source Review (NSR)

Ventura County Rule 26.2.C requires that an Ambient Air Quality Analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an Air Quality Standard (AAQS). Therefore, the VCAPCD has performed an AAQA for this project.

As presented in Section 5 of this document, the proposed project will not cause or contribute significantly to a violation of the State or National Ambient Air Quality Standards (AAQS) for NO_x, CO, SO_x, PM₁₀, or PM_{2.5}.

7.2 Ventura County Rule 51 – Nuisance

Rule 51 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of this operation provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

VCAPCD policy regarding Air Toxic Review of Permit Applications (revised 7/10/02) specifies that if the additional carcinogenic risk associated with new emission units subject to the application is less than 1 in a million, and that the acute and chronic hazard indices are less than 0.5, no further action is required. If the health risk assessment indicates that the additional carcinogenic risk is greater than 10 in a million, or acute or chronic hazard indices are greater than 1, then a health risk reduction plan will be required. Risk assessment results for this project are summarized in the table below.

Table 7-1 RMR Results

Unit Description	Cancer Risk	Hazard Index		Health Risk Reduction Plan Required?
		Chronic	Acute	
Using Adjusted U* Option (Adj-U*)				
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	2.08 x 10 ⁻²	No
Diesel Emergency Engine	5.37 x 10 ⁻⁸	1.66 x 10 ⁻⁵	---	No
Project Total	8.48 x 10 ⁻⁸	9.23 x 10 ⁻⁵	2.08 x 10 ⁻²	No
Not Using Adjusted U* Option				
Natural Gas Turbine	3.81 x 10 ⁻⁸	8.24 x 10 ⁻⁵	4.19 x 10 ⁻²	No
Diesel Emergency Engine	4.22 x 10 ⁻⁸	1.59 x 10 ⁻⁵	--	No
Project Total	7.32 x 10 ⁻⁸	9.12 x 10 ⁻⁵	4.19 x 10 ⁻²	No

The acute and chronic indices are below 0.5 and the cancer risk factor associated with the project is less than 1.0 in a million. In accordance with VCAPCD's Air Toxics Review of Permit Application policy, the project is approved without the need for submittal of a Health Risk Reduction Plan.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT

POLICIES AND PROCEDURES

AIR TOXICS REVIEW OF PERMIT APPLICATIONS

Issued: February 12, 1992

Revised: July 10, 2002

Policy Statement

Each application for an Authority to Construct, or an application for a Permit to Operate when no Authority to Construct was issued, will be reviewed by the Air Toxics Section to determine if a health risk assessment needs to be prepared for the application.

If a health risk assessment is needed, the health risk assessment shall be prepared for the air toxic emissions from the emissions units that are the subject of the application. The health risk assessment shall be prepared in accordance with the current guidelines used for the Air Toxics Hot Spots program.

If the health risk assessment indicates that the additional carcinogenic risk associated with the emissions units that are the subject of the application is less than 1 in a million, and that the acute and chronic hazard indices are less than 0.5, no further action will be required.

If the health risk assessment indicates that the additional carcinogenic risk is greater than 1 in a million, or that the acute or chronic hazard indices are greater than 0.5, District staff will work with the applicant to reduce the risk to an acceptable level.

If, after working with the applicant to reduce the risk, the health risk assessment still indicates that the additional carcinogenic risk is greater than 10 in a million, or that the acute or chronic hazard indices are greater than 1, permit conditions will be placed on the permit requiring the applicant to develop and implement a health risk reduction plan. The plan will be required to be

submitted within 6 months. The plan will be required to show an acceptable reduction in the health risk within 5 years from permit issuance. An acceptable reduction in the health risk will be one that reduces the additional carcinogenic risk to 10 in a million or less and the acute or chronic hazard indices to 1 or less.

If, after working with the applicant to reduce the risk, the health risk assessment still indicates that the additional carcinogenic risk is greater than 100 in a million, or that the acute or chronic hazard indices are greater than 10, the application will be denied based on failure to demonstrate compliance with the Rule 51 – Nuisance.

If the application is subject to the notice requirements of Health and Safety Code Section 42301.6 because the facility is located near a school, appropriate public notice of the application must be provided prior to permit issuance independent of the results of the health risk assessment.

If the application is subject to Rule 36 – New Source Review – Hazardous Air Pollutants because the facility is a major source of hazardous air pollutants, the provisions of Rule 36 apply independent of the results of the health risk assessment.

Background

Rule 15 – Standards for Permit Issuance requires District staff to deny a permit application unless the applicant shows that the emissions units that are the subject of the application will comply with all applicable requirements including Rule 51 – Nuisance.

Health and Safety Code Section 42301.6 requires District staff to provide public notice of any permit application for a source that emits hazardous air pollutants if the application will result in an emissions increase and the facility is located within 1,000 feet from the outer boundary of a school site.

Rule 36 – New Source Review – Hazardous Air Pollutants requires District staff to conduct a case-by-case maximum achievable control technology determination for any facility that is a major source of federal hazardous air pollutants (HAP). For Rule 36, a major source is defined as one that emits 10 tons per year or more of a single HAP or 25 tons per year or more of a combination of HAP.

Discussion

The District does not have a general new source review rule for toxic air pollutants. District staff does, however, consider that an excessive additional

health risk due to the emissions of toxic air pollutants for a new or modified facility is a violation of Rule 51 – Nuisance. The primary object of this policy is, therefore, to define how the Engineering Division will determine if a new, modified, replacement or relocated emissions unit that emits toxic air pollutants can operate in compliance with Rule 51.

Appendix H
Hazardous Air Pollutant Stationary Source
Potential to Emit

Toxics emissions are summarized in the following table:

Table 6-2. Source Process Rates

Pollutant ID	Pollutant Name	Max. Hourly Emissions (lbs) ¹	Annual Emissions (lbs) ²	Emission Factor Origin
Natural Gas Turbine				
7664417	Ammonia	1.75E+01	3.52E+04	Permit Limit
115071	Propylene	7.79E+00	4.82E+03	CATEF ³
75070	Acetaldehyde	4.12E-01	2.55E+02	AP-42 ⁴
107028	Acrolein	6.61E-02	4.09E+01	AP-42
71432	Benzene	1.24E-01	7.65E+01	AP-42
106990	1,3-Butadiene	4.44E-03	2.74E+00	AP-42
100414	Ethylbenzene	3.30E-01	2.04E+02	AP-42
50000	Formaldehyde	9.27E+00	5.73E+03	CATEF ⁴
110543	Hexane	2.62E+00	1.62E+03	CATEF
91203	Naphthalene	1.35E-02	8.35E+00	AP-42
---	Total PAH's (listed individually below)	6.63E-03	4.10E+00	---
83329	Acenaphthene	1.92E-04	1.18E-01	CATEF
208968	Acenaphthylene	1.48E-04	9.17E-02	CATEF
120127	Anthracene	3.42E-04	2.12E-01	CATEF
56553	Benzo(a)anthracene	2.29E-04	1.41E-01	CATEF
50328	Benzo(a)pyrene	1.40E-04	8.66E-02	CATEF
192972	Benzo(e)pyrene	5.50E-06	3.40E-03	CATEF
205992	Benzo(b)fluoranthrene	1.14E-04	7.07E-02	CATEF
207089	Benzo(k)fluoranthrene	1.11E-04	6.88E-02	CATEF
191242	Benzo(g,h,i)perylene	1.38E-04	8.54E-02	CATEF
218019	Chrysene	2.55E-04	1.58E-01	CATEF
53703	Dibenz(a,h)anthracene	2.37E-04	1.47E-01	CATEF
206440	Fluoranthene	4.37E-04	2.70E-01	CATEF
86737	Fluorene	5.87E-04	3.63E-01	CATEF
193395	Indeno(1,2,3-cd)pyrene	2.37E-04	1.47E-01	CATEF
85018	Phenanthrene	3.17E-03	1.96E+00	CATEF
129000	Pyrene	2.80E-04	1.73E-01	CATEF
75569	Propylene oxide	2.99E-01	1.85E+02	AP-42
108883	Toluene	1.35E+00	8.35E+02	AP-42
1330207	Xylene	6.59E-01	4.08E+02	AP-42
Diesel Emergency Engine				
9901	Diesel particulate matter	3.00E-02	6.00E+00	Engine Manufacturer

¹The maximum hourly emissions for the natural gas turbine represent a startup/shutdown scenario with a low catalyst control efficiency that results in an 8.01 time increase in the rate of toxic emissions. This rate of increase was calculated as the ratio of the worst case startup/shutdown hourly VOC emission rate to the normal operation hourly VOC emission rate.

²Annual emissions for the natural gas turbine represent 400 combined startup/shutdown hours and 1,750 normal operation hours.

³Toxic emission factors derived from the California Toxic Emission Factor (CATEF) database. The CATEF emission factors (mean values) were converted to from lb/mmcf to lb/mmBtu using the HHV of natural gas.

⁴Toxic emission factor derived from US EPA's AP-42 Table 3.1-3 (4/00). Since the emission factors presented in AP-42 are uncontrolled, a 50% control efficiency was applied to account for the presence of the oxidation catalyst.

Table D-6 (Revised December 4, 2015)

Puente Power Project

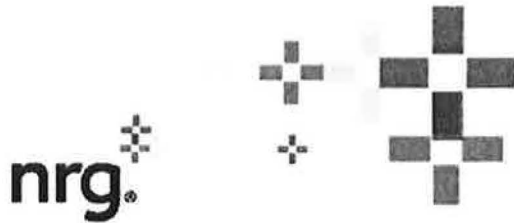
Non-Criteria Pollutant Annual Emissions (maximum 2-year avg. over past 5-years)

MGS Existing Units 1 - 3

Pollutant	Unit 1 Annual Avg Firing Rate MMscf/yr	Unit 2 Annual Avg Firing Rate MMscf/yr	Unit 3 GT Annual Avg Firing Rate MMscf/yr	Unit 1 Annual Emissions tons/yr	Unit 2 Annual Emissions tons/yr	Unit 3 GT Annual Emissions tons/yr	Subtotal tons/yr
Ammonia (not a HAP)	1,102	1,297	89	2.511	2.956	0.000	5.467
Propylene (Not a HAP)	1,102	1,297	89	0.009	0.010	0.034	0.053
Propylene oxide	1,102	1,297	89	0.000	0.000	0.001	0.001
Benzene	1,102	1,297	89	0.001	0.001	0.001	0.003
Formaldehyde	1,102	1,297	89	0.002	0.002	0.041	0.045
Hexane	1,102	1,297	89	0.001	0.001	0.011	0.013
Naphthalene	1,102	1,297	89	0.000	0.000	0.000	0.000
Dichlorobenzene	1,102	1,297	89	0.000	0.000	0.000	0.000
Toluene	1,102	1,297	89	0.004	0.005	0.006	0.015
1,3-Butadiene	1,102	1,297	89	0.000	0.000	0.000	0.000
Acetaldehyde	1,102	1,297	89	0.000	0.001	0.002	0.003
Acrolein	1,102	1,297	89	0.000	0.001	0.000	0.001
Ethyl Benzene	1,102	1,297	89	0.001	0.001	0.001	0.004
PAHs (other)	1,102	1,297	89	0.000	0.000	0.000	0.000
Xylene	1,102	1,297	89	0.003	0.004	0.003	0.010
						Total (HAPs) =	0.095
						Total (All) =	5.615

Appendix I

Certification of Statewide Compliance



NRG Energy Center Oxnard LLC
5790 Fleet Street, Suite 200
Carlsbad, CA 92008
Phone: 760-710-2156
Fax: 760-710-2158

May 13, 2015

Mr. Mike Villegas
Air Pollution Control Officer
Ventura County Air Pollution Control District
669 County Square Drive, 2nd Floor
Ventura, CA 93003

**Subject: Puente Power Project – VCAPCD Rule 26.2.D Statewide Compliance Certification,
Determination of Compliance**

Dear Mr. Villegas,

In accordance with VCAPCD Rule 26.2.D, Statewide Compliance Certification, NRG Energy, Inc. is pleased to provide this compliance statement regarding the proposed Puente Power Project, which is owned by an NRG Energy, Inc. subsidiary, NRG Energy Center Oxnard LLC.

All major stationary sources in California owned or operated by NRG Energy, Inc., or by any entity controlling, controlled by, or under common control with NRG Energy, Inc., and which are subject to emission limitations, are currently in compliance or on a schedule for compliance with all applicable federal Clean Air Act emission limitations and standards. These sources include the following facilities:

- Coolwater Generating Station, Daggett, CA
- El Cajon Combustion Turbine Facility, El Cajon, CA
- Ellwood Generating Station, Goleta, CA
- El Segundo Generating Station, El Segundo, CA
- Encina Power Station, Carlsbad, CA
- Etiwanda Generating Station, Rancho Cucamonga, CA
- Kearny Mesa 1 Facility, San Diego, CA
- Kearny Mesa 2 and 3 Facility, San Diego, CA
- Long Beach Generating Station, Long Beach, CA
- Mandalay Generating Station, Oxnard, CA
- Marsh Landing Generating Station, Antioch, CA
- Midway-Sunset, Fellows, CA (50% owned; not Title V permit holder)
- Miramar Facility, San Diego, CA
- Ormond Beach Generating Station, Oxnard, CA
- Pittsburg Generating Station, Pittsburg, CA
- San Diego District Energy Center, San Diego, CA
- San Francisco Thermal, San Francisco, CA
- Sunrise Power Company, Fellows, CA
- Walnut Creek Energy Park, Industry, CA
- Watson Cogeneration, Wilmington, CA (49% owned; not Title V permit holder)

Mr. Mike Villegas, VCAPCD

May 13, 2015

Page 2

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Please contact George Piantka at 760-710-2156 if you have any questions regarding this certification.

Best Regards,

A handwritten signature in black ink, appearing to read "John Chillemi".

John Chillemi

President

cc: Kerby Zozula, VCAPCD
Leonard Scandura, SJVAPCD
Leland Villavazo, SJVAPCD
Jon Hilliard, CEC
Gerry Bemis, CEC
George Piantka, NRG
Sean Beatty, NRG
Michael Carroll, Latham & Watkins
Tom Andrews, Sierra Research

Appendix J

Analysis of Alternatives



Application for Certification

Puente Power Project (P3)

Oxnard, CA

Volume I



Submitted to:

The California Energy Commission



Prepared by: **AECOM**

5.0 ALTERNATIVES

5.1 INTRODUCTION

The California Environmental Quality Act (CEQA) requires environmental documents to consider “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives” (14 California Code of Regulations [CCR] 15126.6[a]). Therefore, the focus of an alternatives analysis should be on alternatives that “could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects” (14 CCR 15126.6(c)). The CEQA Guidelines further provide that “[a]mong the factors that may be used to eliminate alternatives from detailed consideration in an EIR [Environmental Impact Report] are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts” (14 CCR 15126.6(c)).

A range of reasonable alternatives to the proposed Puente Power Project (P3 or project), or certain elements thereof, is identified and evaluated in this section. These alternatives include:

- The “No Project” alternative (that is, not developing a new power generation facility);
- Alternative generation technologies and configurations;
- Alternative sources of water supply;
- Alternative wastewater handling systems; and
- Alternative emission control technologies.

5.2 PROJECT OBJECTIVES

Applicant has identified several basic objectives for the development of P3:

- Fulfill Applicant’s obligations under its 20-year Resource Adequacy Purchase Agreement (RAPA) with Southern California Edison (SCE) requiring development of 262 megawatts (MW) nominal net output of newer, more flexible and efficient natural gas generation at the site of the existing Mandalay Generating Station (MGS);
- Provide an efficient, reliable, and predictable power supply by using a simple-cycle, natural-gas-fired combustion turbine to replace the existing once-through cooling (OTC) generation;
- Support the local capacity requirements of the California Independent System Operator Big Creek/Ventura Local Capacity Reliability area;
- Develop a 262-MW nominal net power generation plant that provides efficient operational flexibility with rapid-start and fast-ramping capability to allow for efficient integration of renewable energy sources in the California electrical grid;
- Be designed, permitted, built, and commissioned by June 1, 2020;
- Minimize environmental impacts and development costs by developing on an existing brownfield site and reusing existing transmission, water, wastewater, and natural gas infrastructure;
- Site the project on property that has an industrial land use designation with consistent zoning; and
- Safely produce electricity without creating significant environmental impacts.

Project objectives play an important role in determining what constitutes a range of reasonable alternatives to the proposed project. “Under the case law applying CEQA’s definition of feasibility, ‘[a]lthough a lead agency may not give a project’s purpose an artificially narrow definition, a lead agency may structure its EIR alternative analysis around a reasonable definition of underlying purpose and need not study alternatives that cannot achieve that basic goal.’” *Surfrider Found. v. State Water Res. Control Bd.* (2012) 211 Cal. App. 4th 557, 583 (citation omitted). Furthermore, what constitutes a reasonable range of alternatives must be determined in light of the specific context and circumstances under which a project is proposed. “‘CEQA establishes no categorical legal imperative as to the scope of alternatives to be analyzed in an EIR. Each case must be evaluated on its facts, which in turn must be reviewed in light of the statutory purpose.’ ... There is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason.” *Watsonville Pilots Assn. v. City of Watsonville* (2010) 183 Cal. App. 4th 1059, 1086 [citations omitted].

Although all of the project objectives should be taken into consideration when evaluating alternatives to the proposed project, the first project objective identified above is particularly important. It reflects the context in which the State of California plans for and procures its electricity supply. The RAPA is the end result of the California Public Utility Commission’s (CPUC) Long-Term Procurement Plan; CPUC decisions authorizing the procurement of electricity by the state’s investor-owned utilities; and the Request for Offers (RFO) process conducted pursuant to those authorizations. Through the RFO process, the utility evaluates a range of alternatives and awards RAPAs that are technology-specific and location-specific to those projects best suited to meet its needs. The RAPAs are then reviewed and approved by the CPUC. It is then incumbent upon the developer to deliver the project consistent with the terms of the RAPA. Therefore, this objective is not merely a goal or aspiration of the project developer, but a legal imperative. This must be kept in mind when determining what constitutes a range of reasonable alternatives, as well as which alternatives might be considered feasible. Alternatives that fail to satisfy the first project objective are neither reasonable nor feasible, and extensive analysis of such alternatives is unwarranted.

5.3 NO PROJECT ALTERNATIVE

5.3.1 Description

The No Project Alternative “provides the decision makers and the public with specific information about the environment if the project is not approved. It is a factually based forecast of the environmental impacts of preserving the status quo.” *Planning & Conservation League v. Department of Water Resources* (2000) 83 Cal. App. 4th 892, 917, 918. In this case, P3 is intended to replace the generation currently provided by MGS Units 1 and 2. Because there are currently no other gas-fired projects proposed for development in the area, in the absence of P3, MGS Units 1 and 2 may continue to be needed to meet local reliability needs. However, the State Water Resources Control Board’s (SWRCB) Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, also referred to as the OTC Policy, requires that MGS Units 1 and 2 either cease use of ocean water for cooling or reduce the impacts of OTC to a level commensurate with closed-cycle cooling by December 31, 2020. Therefore, the No Project Alternative would be MGS Units 1 and 2 continuing to operate, but with an alternative cooling system that meets the requirements of the OTC Policy.

Prior to the decision to replace MGS Units 1 and 2 with P3, a number of alternative cooling systems for MGS Units 1 and 2 were evaluated (GenOn, 2011). The Mandalay Generating Station 2011 Implementation Plan for the OTC Policy evaluated closed-cycle wet-cooling options using salt (ocean) water and fresh water, including recycled water. Due to logistical, technical, and permitting/environmental constraints, all closed-cycle wet-cooling options were determined to be infeasible. The 2011 Implementation Plan did not evaluate retrofitting MGS Units 1 and 2 with dry cooling. Ultimately, the 2011 Implementation Plan outlined compliance with the OTC Policy through implementation of

technological and/or operational measures to reduce impingement and entrainment to required levels. This approach requires a 3-year impingement and entrainment monitoring program to establish baseline conditions against which to evaluate the effectiveness of the proposed technological and/or operational measures. On May 14, 2012, the compliance strategy laid out in the 2011 Implementation Plan was changed to the current strategy of replacing MGS Units 1 and 2 with new dry-cooled generation (GenOn, 2012).

In the event that P3 did not move forward (i.e., the No Project Alternative), it would be necessary to revisit alternative OTC Policy-compliant cooling systems for MGS Units 1 and 2. The circumstances affecting the feasibility of closed-cycle wet cooling have not changed materially since development of the 2011 Implementation Plan, and those technologies continue to be infeasible. One option would be to revert to the Track 2 compliance strategy laid out in the 2011 Implementation Plan, namely implementation of technological and/or operational measures that may include variable-speed drive pumps to more efficiently manage intake flow and intake screens to reduce entrainment. However, because of the need to conduct a 3-year baseline monitoring program, after which such a strategy change would be implemented, it may not be possible to implement Track 2 prior to the compliance deadline of December 31, 2020. Therefore, notwithstanding certain engineering challenges, retrofitting MGS Units 1 and 2 with dry cooling appears to be the most viable option for bringing those units into compliance with the OTC Policy in the event that P3 does not move forward. This is, therefore, the No Project Alternative.

For the dry-cooling scenario, two ACCs, one for each unit, would be provided. Each ACC would be approximately 130 feet by 290 feet by 100 feet tall. The site would have sufficient space to accommodate this infrastructure. Process water requirements would continue to be met from the existing potable water supply. The amount of potable water would be approximately the same amount of potable water that the MGS currently uses.

5.3.2 Ability of No Project Alternative to Meet Project Objectives

The No Project Alternative would meet certain project objectives. However, it would also fail to meet certain important project objectives. The No Project Alternative would not allow Applicant to fulfill its obligations under the 20-year RAPA with SCE requiring development of newer, more flexible and efficient natural gas generation. Although retrofitting MGS Units 1 and 2 with an alternative cooling system would help support the local capacity requirements, the older generating technology would not provide the same efficient operational flexibility, with rapid-start and fast ramping capability, to allow for efficient integration of renewable energy sources in the California electrical grid.

5.3.3 Potential Environmental Effects of No Project Alternative

Some of the construction-related impacts associated with P3 would be eliminated with the No Project Alternative; however, there would be construction impacts associated with constructing the alternative cooling system. Because MGS Units 1 and 2 are older and less-efficient technology, the No Project Alternative would result in increased fuel and water consumption and air pollution compared to the proposed P3 project.

5.4 ALTERNATIVE SITES

The proposed P3 project site is in the existing MGS site and would be constructed north of the existing power-generating facilities. The proposed site is currently undeveloped, but was previously graded. Construction of the new facility on the proposed site would capitalize on the close proximity to the existing SCE Substation, adjacent to MGS. Additionally, locating P3 within the boundaries of the existing MGS site would allow the reuse of infrastructure such as the ammonia tank, access roads, and

electrical, water, wastewater, and natural gas systems. This would eliminate the need for offsite linear facilities and minimize environmental impacts.

According to Public Resources Code (PRC) 25540.6(b), evaluation of alternative sites is not required when a natural-gas-fired thermal power plant is proposed for development at an existing industrial site such as MGS. P3 is just that type of project that was envisioned by this code section; therefore, it is reasonable not to analyze alternative sites for the project. P3 would be adjacent to the existing SCE switchyard, and because of adjacent existing infrastructure, would minimize the need for offsite linear features. Therefore, evaluation of alternative sites outside the boundaries of the MGS is not required.

In addition, as stated above, CEQA requires environmental documents to consider a range of reasonable alternatives that would feasibly attain most of the basic objectives of the project, but would avoid or substantially lessen any of the significant effects; and states that failure to do either may be grounds for elimination of an alternative. "Although CEQA requires that an EIR identify alternatives to a project, it does not expressly require a discussion of alternative project locations." *Mira Mar Mobile Community v. City of Oceanside*, 119 Cal. App. 4th 477, 491 (2004) (citing PRC §§ 21001 (g), 21002.1(a), 21061). "[T]here is no rule requiring an EIR to explore offsite project alternatives in every case." *California Native Plant Society v. City of Santa Cruz* (2009) 177 Cal. App. 4th 957, 991. An agency may determine that no feasible locations exist either because basic project objectives cannot be achieved at another site, or because there are no sites meeting the criteria for feasible alternative sites. See *City of Long Beach v. Los Angeles Unified Sch. Dist.*, 176 Cal. App. 4th 889, 921 (2009).

It would not be feasible to meet most of the project objectives if P3 was constructed at an alternate site. First and foremost, the RAPA awarded by SCE is location-specific and calls for new generation to be developed at the MGS site. In its RFO process, SCE evaluated numerous proposals at a variety of different locations, and selected the Applicant's proposal at the MGS location as the proposal that best meets its needs. Applicant does not have the ability under the RAPA to select an alternative location for the development of P3. Even if Applicant had the ability to select an alternative location, doing so would not meet other project objectives, including reusing existing infrastructure to minimize development costs and environmental impacts.

Furthermore, Applicant does not have ownership or control over alternative sites on which P3 could be located, and it is unlikely that Applicant could identify, evaluate, and acquire an alternative site, including necessary rights-of-way for gas, water, and transmission infrastructure, and meet its commissioning date of June 1, 2020. "A feasible alternative is one which can be 'accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors.' . . . Surely whether a property is owned or can reasonably be acquired by the project proponent has a strong bearing on the likelihood of a project's ultimate cost and the chances for an expeditious and 'successful accomplishment.' . . . [T]he law does not require in depth review of alternatives which cannot be realistically considered and successfully accomplished . . ." *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. 3d 553, 574–75 [internal citations omitted].

Finally, construction and operation of a power plant at an alternate location would likely result in new, significant environmental impacts associated with the additional construction and operation of infrastructure that would be required because existing plant infrastructure would not be used. This would potentially result in greater impacts related to Air Quality, Biological Resources, Cultural Resources, Hazards and Hazardous Materials, Noise, Soils, Transportation and Circulation, Visual Resources, and Water Resources.

For the reasons set forth above, further evaluation of alternative sites outside the boundaries of the MGS is not required.

5.5 ALTERNATIVE GENERATING CONFIGURATIONS AND TECHNOLOGIES

5.5.1 Proposed Configuration

The proposed configuration includes one General Electric (GE) 7HA.01 natural-gas-fired combustion turbine generator (CTG) operated in simple-cycle mode. The proposed layout has been optimized for plant-operating efficiencies, such as effective use of existing infrastructure and reuse of various facilities, including the ammonia tank and retention basins. The identified location for P3 is the most efficient location within the MGS boundaries that could support a facility of this configuration.

5.5.2 GE LMS-100s

Applicant initially considered use of a GE LMS-100s system. In its response to SCE's RFO for the Moorpark Sub-Area of the Big Creek/Ventura Local Reliability Area, Applicant submitted bids for three options: GE 7HA.01, GE LMS-100s, and conventional combined cycle. Based on the competitive bidding process, SCE selected the GE 7HA.01, and therefore the RAPA requires deployment of this technology. Deployment of alternative generating technology would fail to meet the project objective of meeting the obligations of the RAPA. Therefore, use of a GE LMS-100s system was eliminated from further consideration.

5.5.3 Conventional Combined-Cycle

Applicant initially considered use of a conventional combined-cycle system. As stated above, Applicant proposed a conventional combined-cycle plant as one of three options in response to SCE's RFO. Based on the competitive bidding process, SCE selected the GE 7HA.01, and therefore the RAPA requires deployment of this technology. Deployment of alternative generating technology would fail to meet the project objective of meeting the obligations of the RAPA. Therefore, use of a conventional combined-cycle plant was eliminated from further consideration.

5.6 WATER SUPPLY

P3 would be a dry-cooled facility and would use very little water (less than 20 acre-feet per year [AFY]). P3 will not include a steam cycle, and it will not use water for steam condensation purposes or as part of any process that uses water to reject power plant process heat or waste heat to the atmosphere. P3 will only use water for evaporative cooler makeup, service water, and water for combustion turbine washes. The proposed source of the process water for P3 is potable water provided by the City of Oxnard, the local water supply purveyor.

California Energy Commission (CEC) Staff and the Commission have found that a project deploying essentially the same technology as P3 was not using water for cooling purposes within the meaning of the CEC's policy on the use of fresh water for power plant cooling, as set forth in the CEC's 2003 Integrated Energy Policy Report, and the similar policy in State Water Quality Control Board (SWQCB) Resolution 75-58. (See Commission Decision, Marsh Landing Generating Station [MLGS], Docket 08-AFC-3, pp. 83-84, citing Staff Assessment, Exhibit 300, pp. 4.9-23 through 4.9-25 [CEC, 2010].) These policies specify that the use of fresh water for cooling purposes by power plants will be approved only when alternative water supply sources and alternative cooling technologies are shown to be environmentally undesirable or economically unsound. In the case of MLGS, Staff concluded, and the Commission concurred, that the proposed use of 50 AFY of fresh water supplied by the City of Antioch was consistent with these policies (CEC, 2010). In its Decision, the Commission found:

"The MLGS will use water in CTG inlet air evaporative coolers and for service water and other industrial purposes. The inlet air evaporative coolers use a relatively small amount of water to reduce the temperature of the ambient air as it enters the combustion turbines to improve power

output and efficiency. In this process, water is introduced into the ambient air as it is drawn through the turbine. The MLGS will not use water for wet cooling or as part of a steam cycle or for steam condensation purposes. The MLGS also will not use any water for the purpose of rejecting waste heat produced by power plant processes to the atmosphere. Staff concluded that the MLGS will not use water for cooling purposes because it utilizes a project design that minimizes the use of water . . . We find that the Marsh Landing Project's use of either brackish groundwater or fresh water supplied by the City of Antioch for process uses will comply with Energy Commission water policy and SWQCB Resolution 75-58." (citations omitted)

The technology to be deployed at P3, and the purposes for which water will be used, are essentially the same as in the case of the MLGS. The only material difference is that P3 will use considerably less water than even MLGS.

5.6.1 Recycled Water

As discussed above, the availability of recycled water (i.e., tertiary treated wastewater) at the MGS site was carefully evaluated in the 2011 Implementation Plan developed in connection with the OTC Policy. At that time, it was concluded that recycled water was not available at the MGS site. The circumstances surrounding the availability of recycled water have not changed materially since that time. The use of recycled municipal wastewater for process water needs at the P3 is still considered to be infeasible for the reasons provided below.

1. The City of Oxnard began construction of its Advanced Water Purification Facility (AWPF) in 2009. The plant currently is undergoing its final commissioning process. It is anticipated that the plant will begin operations in spring 2015. The Recycled Water Backbone System has been completed. This main pipeline will convey recycled water from the AWPF, north along Perkins, C Street, and Ventura Road to the River Ridge Golf Course, near the Santa Clara River. The first phase of the recycled water production capacity is 6.25 million gallons per day (MGD), or 7,000 AFY. Approximately, 1,500 AFY to 1,800 AFY of this will be delivered to the River Ridge Golf Club for irrigation. The remaining 5,200 to 5,500 AFY of recycled water will be delivered to an aquifer storage and recovery well that the City plans to construct in 2015, and to agricultural customers (Rydberg, 2014). The closest connection point from the P3 site to the City of Oxnard's Recycled Water Backbone System is more than 4 miles away (near Fifth Street and Ventura Road), and construction of a pipeline through already congested utility corridors to interconnect would be economically infeasible, considering the small amount of water used by P3.
2. The City of Ventura owns and operates the Ventura Water Reclamation Facility (VWRF), north of the Santa Clara River. Currently, the VWRF generates approximately 9 MGD of tertiary treated wastewater. This water is used for irrigation of golf courses, parks, and landscaping in the City of Ventura, and is discharged to the Santa Clara River Estuary (just north of the river where the river discharges to the ocean) under an order from the Los Angeles Regional Water Quality Control Board. Recently, in compliance with the renewal of the discharge permit, the City of Ventura has been conducting special studies for the Santa Clara River Estuary to assess continued discharge of the recycled water to the estuary or identify other potential customers, for uses such as urban and agricultural irrigation throughout the City of Ventura, and groundwater recharge and other uses outside the City of Ventura (Carollo and Stillwater Sciences, 2011; Carollo, 2014).

The VWRF is outside the boundaries of, and does not serve, the City of Oxnard. There is no connectivity between the City of Oxnard's water system and the VWRF distribution system. If the proposed project were to obtain recycled water from the VWRF, it would require installation of an approximately 2.5-mile-long pipeline along North Harbor Boulevard and across a large river (i.e., the Santa Clara River). Such an installation, assuming this water supply would be

available, would be considered economically infeasible given the small quantity of water needed by P3. An interconnection to an outside water purveyor may not even be administratively feasible.

3. The next closest facilities are 10 miles or more away from the site, and extensive infrastructure would be required to deliver recycled water, if even available, to the site. These facilities include:
 - The Ojai Valley Wastewater Treatment Plant is approximately 10 miles north of P3; it currently does not produce recycled water (Casitas Municipal Water District, 2011).
 - Camrosa Water Reclamation Facility is in the City of Camarillo, approximately 15 miles southeast of P3; it currently produces approximately 1.5 MGD of reclaimed water (Camrosa Water District, 2015)
 - Santa Paula Water Recycling Facility is approximately 12 miles northeast of P3; it currently produces approximately 3.4 MGD of recycled water (Santa Paula Water District, 2015).
 - The City of Fillmore Water Recycling Plan produces approximately 1.8 MGD of recycled water and is more than 20 miles away from P3 (American Water, 2015).
 - The Moorpark Wastewater Treatment Plan produces approximately 5 MGD of recycled water and is more than 20 miles away from P3 (PSOMAS, 2014).

There is no connectivity between the City of Oxnard's water system and any of these other water purveyors. Tertiary-treated recycled water is not feasibly available from these facilities due to jurisdictional, supply, and interconnection constraints. Accordingly, based on currently available information, recycled water supplies are not available.

P3 will deploy dry-cooling technology and use only a small quantity of potable water. Consistent with the MLGS Decision, the proposed use does not constitute use of fresh water for power plant cooling as governed by applicable CEC and SWQCB policies. There is an existing water supply line on the MGS property, and no new offsite infrastructure will be required to deliver water to the project. Use of recycled water would require construction of costly new pipelines, with resulting environmental impacts and disruptions due to construction in congested routes. Under these circumstances, even if P3's proposed water use fell within the scope of applicable policies, use of recycled water as an alternative water supply would be environmentally undesirable and economically unsound.

Furthermore, as discussed in Section 4.15, Water Resources, the quantity of potable water used for the proposed replacement project will be substantially less than what is currently used, which reduces the impact on the local water supply, and is a substantial benefit to the region.

5.6.2 Irrigation Return Flow

Agriculture is a major industry in Ventura County and the City of Oxnard. In the vicinity of the project site, strawberries and row crops are the predominant crop types (Larry Walker Associates, 2013).

Discharges from irrigated agricultural lands in Ventura County, including irrigation return flows, flows from tile drains, and stormwater runoff, must comply with the Los Angeles Regional Water Quality Control Board's Conditional Waiver of Waste Discharge Requirements for Discharges from Irrigated Lands within the Los Angeles Region ("Conditional Waiver," Order No. R4-2010-0186).

These discharges can affect water quality by transporting nutrients, pesticides, sediment, salts, and other pollutants from cultivated fields into surface waters, potentially impairing designated beneficial uses of

receiving water bodies. The Ventura County Agricultural Irrigated Lands Group (VCAILG) is a group of landowners and growers that have joined together to comply with the Conditional Waiver as a “Discharger Group.”

The Oxnard Central Drain collects agricultural discharges from approximately 447 acres of farmland in northwestern Oxnard. A VCAILG monitoring site is located on the Oxnard Central Drain near Harbor Boulevard and Gonzales Road, approximately 1 mile north of the P3 site. The Oxnard Central Drain is monitored periodically during the year, usually one or two wet events and one or two dry events. For the 12 events monitored in 2007, 2009, 2010, and 2012, monitoring results indicate that flow in the drain has ranged from approximately 0.36 cubic foot per second (cfs) (dry period in July 2012) to 93.2 cfs (wet period in January 2010). Water quality exceeded benchmarks for nitrates, copper, and pesticides. Total dissolved solids exceeded 2,500 milligrams per liter for 9 of the 12 events (Larry Walker Associates, 2008, 2009, 2010, 2011, 2013).

Irrigation return flow is considered infeasible due to the cost of infrastructure that would be required to deliver the water to the project site, the unreliability of the flows, and the cost of treatment, if the water is even available. The use of irrigation return flow from the Oxnard Central Drain is considered impracticable for the following reasons:

- An extensive and costly infrastructure system would be required to deliver the water from the drain to the site. A pipeline would need to be constructed within the existing road rights-of-way along Harbor Boulevard, between the site and the drain (approximately 1 mile). A pump station would likely be required because of the generally flat terrain.
- The drain provides an unreliable source of water. The amount of water that is available depends on how the fields are operated, and how much irrigation water is applied and when; which in turn depends on the crop, climate, etc. Based on the data from VCAILG for recent monitoring, flow at the Oxnard Center Drain is highly variable throughout the year and from year to year. Because there are only periodic data available, it is uncertain if there is a sustained minimum flow at the drain.
- As a result of increased water conservation measures by growers, including more efficient irrigation practices and conversion to more water-efficient crops, irrigation return flows would be expected to become an increasingly unreliable source of water.
- The irrigation return flow may require treatment for use at the plant. The limited water quality data that are available for the Oxnard Central Drain indicate that the water would be expected to have elevated amounts of nitrates, pesticides, salts, and minerals.

5.6.3 Desalination

The existing MGS Units 1 and 2 currently use ocean water for once-through-cooling. The intake is located in the Edison Canal, and discharge is through the existing outfall structure. The proposed project could use ocean water as a supply for process water needs. The ocean water would require treatment at an onsite desalination facility. Desalination systems need to run continuously to be efficient and cost-effective. P3 is a peaking facility that will operate up to a 30 percent capacity factor. In addition, the very small amount of water needed by P3 does not justify the costs for constructing and operating an onsite desalination facility.

There are no regional desalination plants in the project region. The closest desalination plant to the project site is the Charles E. Meyer Desalination Facility in Santa Barbara, California, which is more than 40 miles away. This plant is currently mothballed and not in operation. It was constructed more than

20 years ago, but was never used. However, the City of Santa Barbara is currently evaluating water supply alternatives, including potentially starting this desalination plant.

Even if this plant were to begin operating, the distance makes connection to the project site economically infeasible.

5.6.4 Onsite Groundwater

Groundwater underlying the MGS property has been impacted by historical SCE (i.e., the former owner of MGS) operations. A Land Use Covenant will reportedly be put in place, restricting the use of groundwater pumped from the site. Therefore, this alternative water supply has not been considered for the proposed project.

5.7 WASTEWATER DISCHARGE

P3 will discharge construction wastewater, process wastewater and stormwater to the existing MGS retention basins, and discharge via the existing outfall structure to the ocean in accordance with MGS' existing Waste Discharge Requirements (WDR) Order No. 01-057, National Pollutant Discharge Elimination System Permit Number CA0001180 (LARWQCB, 2001). Sanitary wastewater will be discharged to the existing MGS septic system in accordance with WDR Order No. R4-2008-0087 (LARWQCB, 2008). Reuse and repurposing of existing infrastructure minimizes the environmental impact footprint.

P3 will use inlet-air evaporative coolers and dry-cooling technology to reduce water consumption. P3 does not include a steam cycle and will not use water for steam condensation purposes. The project will use a reverse osmosis system to recycle process wastewater for reuse on site, further reducing process water demand. The project will incorporate water recycling from the evaporative cooling blowdown, and reuse this water in the cooling-water system.

The project evaluated the use of zero-liquid discharge (ZLD) technology. It was determined that the use of this technology for P3 is not viable for the following reasons: increased capital costs, increased annual operation costs, required transport and disposal of sludge to an offsite landfill, and consumption of energy, which reduces power plant output and efficiency. Considering the very small amount of water consumed by the proposed project (less than 20 AFY), the resulting small amount of wastewater (less than 10 AFY), and water quality and treatment considerations, the use of ZLD is not considered an economically viable alternative.

5.8 ELECTRIC TRANSMISSION LINES

P3 would interconnect at the existing SCE switchyard, which is adjacent to the MGS site. Because the P3 transmission line would be very short and would connect directly into the SCE switchyard without the construction of offsite transmission lines, no alternative electric transmission routes were considered.

5.9 NATURAL GAS SUPPLY LINE

Natural gas will be delivered to P3 by SoCalGas, which currently delivers natural gas to the MGS site. Natural gas will be provided using a new 10-inch-diameter line that will connect to a new gas metering station adjacent to the project site. The connection line will continue generally westward to a new gas compression enclosure on the P3 site. Because the gas pipeline interconnection is short and runs through existing power-generating facilities, no alternative gas pipeline routes were considered.

5.10 ALTERNATIVE AIR POLLUTION EMISSION CONTROL ANALYSIS

The project must comply with the requirements of the Ventura County Air Pollution Control District's (VCAPCD) permit regulations requiring the application of the Best Available Control Technology (BACT) to control air emissions. To comply with the VCAPCD's BACT requirements for oxides of nitrogen (NO_x), the project's design includes dry low-NO_x combustion controls on the gas turbines and selective catalytic reduction (SCR) to control NO_x emissions. To comply with VCAPCD's BACT requirements for reactive organic compounds (ROCs), a carbon monoxide (CO) catalyst will be employed.

The SCR system for the CTG will operate with aqueous ammonia injected into the exhaust gas stream upstream of a catalyst bed to reduce NO_x to inert nitrogen and water. The SCR technology proposed for P3 uses a 19 percent solution of ammonia to reduce NO_x emissions to elemental nitrogen, water, and a small quantity of unreacted ammonia. Although the use and storage of ammonia would represent a potential risk to the public in the event of a catastrophic breach of the storage tank, the offsite consequence analysis (presented in Section 4.5, Hazardous Materials Management) shows that the potential impacts associated with the project's use and storage of ammonia would not result in a significant public health impact.

The remainder of this section presents alternative NO_x emission control technologies considered for the project. The information presented below is based on the air quality analysis presented in Section 4.1, Air Quality.

Potential NO_x control technologies for combustion gas turbines include the following:

- Combustion controls
 - Dry combustion controls
 - Dry low-NO_x combustor design
 - Catalytic combustors (e.g., XONON™)
- Post-combustion controls
 - Selective non-catalytic reduction (SNCR)
 - Non-selective catalytic reduction (NSCR)
 - SCONO_x™

The technical feasibility of available NO_x control technologies is presented below.

5.10.1 Combustion Modifications

5.10.1.1 Dry-Combustion Controls

Combustion modifications that lower NO_x emissions without wet injection include lean combustion, reduced combustor residence time, lean pre-mixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor's primary combustion zone to cool the flame, thereby reducing the rate of thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NO_x formation. Dry low-NO_x combustion would be used on the GE 7HA.01 CTG for this project.

Catalytic combustors use a catalytic reactor bed mounted in the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name Xonon™ in a 1.5-MW natural-gas-fired combustion turbine in Santa Clara, California. No turbine vendor, other than

Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time, and the largest size is 18 MW. The technology is not commercially available for the proposed P3 turbine and other similarly sized combustion turbines; therefore, it is not considered further.

5.10.1.2 Wet-Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NO_x control techniques. These wet-injection techniques lower the peak flame temperature in the combustor, reducing the formation of thermal NO_x. The injected water or steam exits the turbine as part of the exhaust. Although the lower peak flame temperature has a beneficial effect on NO_x emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, emissions of CO and reactive organic gases increase as water/steam injection rates increase.

Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years, so these NO_x control technologies are generally considered technologically feasible and widely available. Because dry low-NO_x combustion controls are used in the GE 7HA.01 CTG and are more effective than water injection, water injection is not considered for this project.

5.10.1.3 Post-Combustion Controls

Selective catalytic reduction is a post-combustion technique that controls both thermal and fuel-bound NO_x emissions by reducing NO_x with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NO_x conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NO_x combustion controls. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control are in excess of 90 percent. SCR would be used on this project, in conjunction with the dry low-NO_x combustion controls on the GE 7HA.01 CTG.

SNCR involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,200 degrees Fahrenheit (°F) to 2,000°F, and is most commonly used in boilers. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for P3.

NSCR uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary internal combustion engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust, where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for P3.

The SCONO_xTM system, also known as EMXTM, is an add-on control device that reduces emissions of multiple pollutants. SCONO_xTM uses a single catalyst for the reduction of CO, volatile organic compounds (VOCs), and NO_x, which are converted to carbon dioxide (CO₂), water, and nitrogen.

The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes nitric oxide to nitrogen dioxide, CO to CO₂, and VOCs to CO₂ and water; while nitrogen dioxide is adsorbed onto the catalyst surface, where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONO_x potassium carbonate layer has a limited adsorption capability, and requires regeneration approximately every 12 to 15 minutes in normal service. Each regeneration cycle requires

approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a SCONOX system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

All installations of the technology have been on small, natural-gas facilities, and all of those facilities have experienced performance issues. The fact that SCONOX™ has not been applied to large-scale natural-gas CTGs like the GE 7HA.01 creates concerns regarding the feasibility.

In a recent BACT analysis performed by SCAQMD for the Redondo Beach Energy Project, SCAQMD engineers did carry forward SCONOX™ as a potential control for its turbines; however, the turbine proposed for this project is considerably larger (260 MW vs. 132 MW on the Redondo Beach Energy Project), and it remains true that SCONOX™ has not been demonstrated in practice on a turbine similar to that proposed for P3. For the above reasons, SCONOX™ is considered technically infeasible to meet the 2-parts per million NO_x emission level that can be achieved with SCR.

5.10.2 Alternatives to Ammonia-Based Emission Control Systems

Over the last few years, several vendors have designed urea-based systems to generate ammonia on site, thereby eliminating the need to transport and store ammonia. These units are referred to as Ammonia on Demand and Urea-to-Ammonia (U2A) systems. The U2A system has limited commercial availability.

The U2A system generates ammonia from solid dry urea. The process starts by dissolving urea in deionized water to produce an aqueous urea solution. Steam is used in the U2A reactor to convert the urea solution into a gaseous mixture of ammonia, CO₂, and water for use in the SCR system. The U2A technology has not been widely applied and accepted for use at simple-cycle or combined-cycle turbine facilities. Aqueous ammonia is currently used at the MGS site. Site personnel are trained and familiar with the safe handling and operation of the systems. Therefore, the U2A system is not considered for this project.

5.11 ALTERNATIVE TECHNOLOGIES

Although the SCE RFO included solicitation for renewable generation, the Applicant's offer was for a natural-gas-fired facility that would integrate with renewables. Therefore, the following alternative technologies were not considered because their use would not meet project objectives:

- Hydrogen-fired
- Biomass
- Solar
- Wind
- Oil
- Coal
- Nuclear
- Hydroelectric
- Geothermal
- Fuel cells

Alternative generating processes, such as solar or wind, generation plants, or use of "clean fuels," such as hydrogen or biomass, represent a completely different family of power generation plant designs from natural-gas peaking and combined cycle plants. Although hydrogen-fired or biomass-fired generation facilities may have certain similar components, such as cooling towers and turbine generators, the technical basis for these plants differs markedly from the natural-gas plant represented in the RAPA. In

addition, natural gas is a clean fuel, with its lower sulfur dioxide and particulate emissions than alternative fossil fuels; and in some cases, natural gas plants may be cleaner than combustion of hydrogen or biomass.

Use of solar or wind generation would not meet a couple of the primary objectives of the project, namely SCE's RAPA, and generation that would integrate renewable energy. Solar or wind generation therefore is not considered further as an alternative technology. Hydrogen-fired or biomass-fired generation would likewise not meet SCE's RAPA. Furthermore, space requirements, water use, and the cost of generation for these alternative technologies are relatively high compared to natural-gas-fired technologies, and may not allow for the same operating flexibility that the natural-gas-fired technologies provide.

Alternative fossil fuels such as oil and coal were not considered, due to the relatively lower efficiency and higher emissions of air pollutants per kilowatt-hour generated. Furthermore, the use of these fossil fuels is counter to California policy on use of lower carbon technologies.

California law prohibits new nuclear plants until the scientific and engineering feasibility of disposal of high-level radioactive waste has been demonstrated. To date, the CEC is unable to make the findings of disposal feasibility required by law for this technology to be viable in California. This technology, therefore, is not possible at this time.

Most of the sites for hydroelectric facilities have already been developed in California, and the remaining potential sites face lengthy environmental licensing periods. It is doubtful that this technology could be implemented within 3 to 5 years, and the cost would probably be higher than the cost of a conventional simple-cycle combustion turbine. There are no hydroelectric sites in the project area.

Geothermal development is not viable at the project location because suitable thermal resources and strata are not present. Therefore, geothermal was eliminated from consideration.

Fuel cells cleanly and efficiently convert chemical energy from hydrogen-rich fuels into electrical power and usable high quality heat in an electrochemical process, with minimal emission of pollutants. Fuel cell power plant applications come in building blocks of 1.4 MW. The largest stationary fuel cell power plant currently installed in the United States is 11.2 MW. To generate electricity, fuel cells require a continuous supply of fuel. The fuel can be any hydrogen-rich fuel, including natural gas or biogas. Fuel cells are not a viable option at this site for the following reasons: the technology has not been proven at the scale needed for the project; fuel cell plants are not engineered to be dispatchable or operate in a peaking manner; and fuel cells are significantly less efficient than the simple-cycle CTG technology proposed for P3. For all of these reasons, this technology would not be considered technologically or economically feasible for a 262-MW (nominal net) facility that needs to provide rapid-start and fast-ramping capability to allow for efficient integration of renewable energy sources.

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Appendix K

Draft DOC Conditions

Puente Power Project 262 MW GE 7HA.01 Combustion Turbine Generator (CTG)

The CTG is simultaneously subject to the emission limits, monitoring requirements, source testing requirements, and recordkeeping and reporting requirements of the following rules and regulations:

Rule 26.2, New Source Review - Requirements

Rule 29, Conditions On Permits

Rule 64, Sulfur Content of Fuels

Rule 74.23, Stationary Gas Turbines

Rule 103, Continuous Monitoring Systems

40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS)

40 CFR Part 60, Subpart A, General Provisions

40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

40 CFR Part 75, Continuous Emissions Monitoring

The following conditions describe and streamline the most stringent requirements of the above rules and regulations. The Ventura County APCD has been delegated authority for 40 CFR Part 60 Subpart KKKK and is considered to be the Administrator.

The Rule 26 BACT NO_x emission limit (2.5 ppmvd at 15% O₂) is the most stringent in comparison to the Rule 74.23 limit (9 ppmvd at 15% O₂) and the NSPS Subpart KKKK NO_x emission limit (15 ppmvd at 15% O₂); therefore the Rule 74.23 and NSPS emission limits are subsumed. However, there are no startup, shutdown, or load change exemption periods from the NSPS Subpart KKKK NO_x concentration limit; therefore, the permittee will need to monitor compliance with the NSPS limit with a 4-hour rolling average NO_x emission rate.

Compliance with the terms of the conditions below for the Puente Power Project CTG assures compliance with all individual requirements applicable to the CTG which have been addressed above and below.

1. Prior to completion of construction, the permittee shall submit an application for a revised Title V Part 70 Permit for the Mandalay Generating Station. The application shall also include the Title IV Acid Rain Permit application, VCAPCD Permit to Operate application, and all applicable supplementary forms and filing fees. (Rules 10, 33, 34)
2. Prior to operation of the new CTG, permittee shall surrender NO_x emission reduction credits (ERCs) in the amount of 38.91 tons per year. Permittee shall cancel the permit

for Mandalay Generating Station (MGS) Unit 2 prior to the commissioning of the new Puente Power Project CTG. (Rule 26.2)

3. Permittee shall use any of the following ERC Certificates to satisfy the NO_x emission offset requirements of Rule 26.2: ERC Certificate Nos. 1078, 1079, 1080, 1083, 1085, 1091, 1092, 1094, 1097, 1104, and / or 1107. (Rules 26.2)
4. The combustion turbine generator (CTG) lube oil vents and the electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents to no greater than 5% opacity, except for no more than three minutes in any one hour. (Rule 26)
5. The CTG shall be operated with a continuously recording fuel gas flowmeter. The flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, a gas fuel flowmeter that meets the installation, certification, and quality assurance requirements of Appendix D to 40 CFR Part 75 is acceptable for use. (Rules 26.2 and 74.23, 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75)
6. The CTG exhaust after the SCR (selective catalytic reduction) unit shall be equipped with continuously recording emissions monitors (CEM) for NO_x, CO, and O₂. Continuous emissions monitors shall meet the requirements of Rule 74.23, Rule 103, 40 CFR Part 60, Appendices B and F, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75, Appendices A and B, as applicable, and shall be capable of monitoring emissions during startups, shutdowns, and unplanned load changes as well as normal operating conditions. (Rules 74.23 and 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)
7. CEM cycling times shall be those specified in 40 CFR Part 60, Subpart KKKK and 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. For NO_x monitoring for 40 CFR Part 60 Subpart KKKK, during each full unit operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_x emission rate for the hour. (Rule 103 and 40 CFR Part 60 Subpart KKKK)
8. The exhaust stack of the CTG shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. (Rules 74.23, 101, and 102)

9. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75 Appendix F, and 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. (Rule 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)
10. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District upon request. (Rule 103)
11. The permittee shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F at least once every four calendar quarters. The permittee shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 75, Appendix B at least once every two calendar quarters unless the permittee achieves 7.5% or below relative accuracy, then permittee meets the incentive of 7.5% or less relative accuracy, then perform RATA once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. (Rule 103 and 40 CFR Part 75)
12. The permittee shall report any violation of the NO_x and CO emissions limit of this permit, as measured by the CEMS, in writing to the District within 96 hours of each occurrence. (Rule 103)
13. The permittee shall maintain permanent continuous monitoring records, in a form suitable for inspection, for a period of at least five (5) years. Such records shall be made available to the Air Resources Board or the District upon request. The report shall include the following:
 - Time intervals of report,
 - The date, time and duration of any startup, shutdown or malfunction in the operation of the gas turbine and CEMS,
 - The results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of the CEMS,
 - Emission Measurements, and
 - Net megawatt-hours produced. (Rule 103)
14. Upon written request of the APCO, the permittee shall submit a written CEM report for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following:

Time intervals of report,

The date, time, duration and magnitude of excess emissions of NO_x and/or CO, the nature and cause of the excess (if known), the corrective actions taken, and the preventive measures adopted,

The averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard,

The date, time and duration of each period during which the CEMS was inoperative, except for zero and span checks, and a description of the system repairs and adjustments undertaken during each period, and,

A negative declaration when no excess emissions occurred. (Rule 103)

15. For the purposes of 40 CFR Part 60, Subpart KKKK, excess emissions shall be defined as any unit operating period in which 4-hour rolling average NO_x concentration exceeds the applicable emissions limit of 15 ppmvd NO_x at 15% O₂ of Part 60.4320, Table 1. The 4-hour rolling average is the arithmetic average of the average NO_x concentration in ppm measured by the CEMS for a given hour (corrected to 15 percent O₂) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_x or O₂. (40 CFR Part 60 Subpart KKKK)
16. For the purposes of 40 CFR Part 60, Subpart KKKK, the permittee shall submit reports of NO_x excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) on a semi-annual basis. In addition, permittee shall submit the results of the initial and annual source test for NO_x. All semi-annual reports of excess emissions and monitor downtime shall be postmarked by the 30th day following the end of each six-month period, or by the close of business on the 60th day following the completion of the source test. (40 CFR Part 60 Subpart KKKK)
17. For the purposes of 40 CFR Part 60, Subpart KKKK, if the total duration of NO_x excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form in 40 CFR Part 60.7(d) shall be submitted and the excess emission report described in 40 CFR Part 60.7(c) need not be submitted unless requested by the EPA or the VCAPCD. (40 CFR Part 60 Subpart KKKK)
18. The ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. All data shall be reduced to hourly averages. (Rule 74.23 and 40 CFR Part 60 Subpart KKKK)

19. Permittee shall monitor and record exhaust gas temperature at the oxidation catalyst inlet and the selective catalytic reduction (SCR) catalyst inlet. All data shall be reduced to hourly averages. (Rule 74.23 and 40 CFR Part 60 Subpart KKKK)
20. The CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as sulfur) per 100 dry scf of natural gas. (Rules 26.2 and 64, 40 CFR Part 60 Subpart KKKK)
21. The sulfur content shall be: (i) documented in a valid purchase contract, supplier certification, tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the sulfur content is less than 0.75 gr/100 scf for 8 consecutive weeks, then the Monitoring frequency shall be once every six (6) months. If any six (6) month monitoring shows an exceedance, weekly monitoring shall resume. (Rules 26.2 and 64 and 40 CFR Part 60 Subpart KKKK)
22. Startup is defined as the period beginning with turbine initial firing. Shutdown is defined by the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Unplanned load change is defined as the automatic release of power from the turbine and the subsequent restart. For an unplanned load change, the loss of power during the release must exceed forty (40) percent of the turbine rating. Startup, shutdown, and unplanned load change durations shall not exceed 60 minutes (1 hour) for a startup, 60 minutes (1 hour) for a shutdown, and 60 minutes (1 hour) for an unplanned load change, per occurrence. For failed start-ups, each restart shall begin a new exemption period. (Rules 26.2, 29, and 74.23)
23. The CTG, air pollution control equipment, and monitoring equipment shall be in operated in a manner consistent with good air pollution control practice for minimizing emissions at all times including during startup, shutdown, and malfunction. (40 CFR Part 60 Subpart KKKK)
24. The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. The information must be sufficient to allow the District to determine compliance with the NO_x emission limits of this permit when the CEMS is not operating properly. (Rules 26.2, 29, and 74.23)
25. The HHV (higher heating value) and LHV (lower heating value) of the natural gas combusted shall be determined upon request using ASTM D3588, ASTM 1826, or ASTM 1945. (Rules 26.2, 29, and 74.23)
26. When the CTG is operating, ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 300 degrees F. Permittee shall monitor and record catalyst temperature during periods of startup. (Rules 26.2 and 74.23)
27. During startup of the CTG, emissions (in pounds = lbs) from the CTG in any one hour shall not exceed any of the following limits:

ROC = 20.30 lbs,
NOx (as NO₂) = 98.87 lbs,
PM₁₀ = 8.75 lbs,
SOx (as SO₂) = 5.50 lbs, and
CO = 178.55 lbs

If the CTG is in startup mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour.

Compliance with the ROC, NOx, PM₁₀, and CO emission limits shall be verified by CTG manufacturer's emission data. Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. In addition, compliance with the NOx and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the permittee shall provide documentation, including a certified source test, correlating the control system operating parameters to the associated measured NOx and CO emissions. (Rules 26.2, 29, and 74.23)

28. During shutdown of the CTG, emissions (in pounds = lbs) from the CTG in any one hour shall not exceed any of the following limits:

ROC = 30.28 lbs,
NOx (as NO₂) = 22.98 lbs,
PM₁₀ = 9.58 lbs,
SOx (as SO₂) = 5.50 lbs, and
CO = 163.48 lbs

If the CTG is in shutdown mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour.

Compliance with the ROC, NOx, PM₁₀, and CO emission limits shall be verified by CTG manufacturer's emission data. Compliance with the SOx emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. In addition, compliance with the NOx and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the permittee shall provide documentation, including a certified source test, correlating the control system operating parameters to the associated measured NOx and CO emissions. (Rules 26.2, 29, and 74.23)

29. During normal operation of the CTG, emission concentrations and emission rates from the CTG, except during startup, shutdown, and/or unplanned load change, shall not exceed any of the following limits:

ROC = 6.60 pounds per hour and 2.0 ppmvd @ 15% O₂,
NOx (as NO₂) = 23.73 pounds per hour and 2.5 ppmvd @ 15% O₂,
PM₁₀ = 10.10 pounds per hour,
SOx (as SO₂) = 5.50 pounds per hour,
CO = 23.10 pounds per hour and 4 ppmvd @ 15% O₂,

Ammonia (NH₃) = 17.53 pounds per hour and 5 ppmvd @ 15%O₂.

ROC and NO_x (as NO₂) ppmvd and pounds per hour limits are expressed as a one-hour rolling average limit. All other ppmvd and pounds per hour limits are three-hour rolling averages. If the CTG is in either startup or shutdown mode during any portion of a clock hour, the CTG shall not be subject to these limits during that clock hour. Startup limits and shutdown limits are listed in the above conditions.

Compliance with the ROC, NO_x, PM₁₀, CO, and NH₃ emission limits shall be verified by initial and annual source testing as required below. Compliance with the SO_x emission limit shall be verified by complying with the natural gas sulfur content limit of this permit. Compliance with the NH₃ limits shall also be verified by monitoring the ammonia injection rate as required below. In addition, compliance with the NO_x and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the permittee shall provide documentation, including a certified source test, correlating the control system operating parameters to the associated measured NO_x and CO emissions. (Rules 26.2, 29, and 74.23)

30. Emissions rates from the CTG during the commissioning period shall not exceed the following limits:

ROC = 164.10 pounds per hour and 3.52 tons per year,
NO_x (as NO₂) = 246.30 pounds per hour and 11.70 tons per year, and
CO = 1973.00 pounds per hour and 31.74 tons per year.

The commissioning period is the period of time commencing with the initial startup of the turbine and ending after 366 hours of turbine operation, or the date the permittee notifies the District the commissioning period has ended. For purposes of this condition, the number of hours of turbine operation is defined as the total unit operating minutes during the commissioning period divided by 60.

Compliance with the ROC, NO_x and CO emission limits shall be verified by CTG manufacturer's emission data. In addition, compliance with the NO_x and CO emission limits shall be verified by continuous emissions monitors (CEMS) as required by this permit. If the CEMS is not operating properly, as required below, the permittee shall provide documentation, including a certified source test, correlating the control system operating parameters to the associated measured NO_x and CO emissions. (Rules 26.2, 29, and 74.23)

31. Annual emissions from the CTG calculated on a twelve consecutive calendar month rolling basis shall not exceed any of the following limits:

ROC = 10.84 tons per year,
NO_x (as NO₂) = 32.95 tons per year,
PM₁₀ = 10.68 tons per year,
SO_x (as SO₂) = 5.91 tons per year, and
CO = 54.42 tons per year.

These tons per year limits include normal operation, startups, shutdowns, unplanned load changes, and the commissioning period.

Compliance with the NO_x and CO emission limits shall be verified with the CEMS. In addition, compliance with the NO_x and CO emission limits shall be verified with initial and annual source testing combined with compliance with the CTG's annual operating limit in hours per year.

Compliance with the ROC and PM₁₀ emission limits shall be verified with initial and annual source testing combined with compliance with the CTG's annual operating limit in hours per year.

Compliance with the SO_x emission limit shall be verified by complying with the natural gas sulfur content limit of this permit combined with compliance with the CTG's annual operating limit in hours per year. (Rules 26.2 and 29)

32. Each one-hour period in a one-hour rolling average, three-hour rolling average, or four-hour rolling average shall commence on the hour. (Rules 26.2 and 29)
33. Each calendar month in a twelve consecutive calendar month rolling emissions calculation will commence at the beginning of the first day of the month. The twelve consecutive calendar month rolling emissions total to determine compliance with the annual tons per year emissions limits shall be compiled for each and every twelve consecutive calendar month rolling period. (Rules 26.2 and 29)
34. The ammonia (NH₃) slip emission concentration limit shall be verified by initial and annual source testing as required below, and by the continuous recording of the ammonia injection rate to the SCR system. The correlation between the gas turbine heat input rate, the SCR system ammonia injection rate, and the corresponding ammonia (NH₃) slip emission concentration shall be determined in accordance with required initial and annual ammonia source testing. Alternatively, the permittee may utilize a continuous in-stack ammonia (NH₃) slip monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using an ammonia (NH₃) slip continuous in-stack monitor, the permittee shall submit a monitoring plan to the District for review and approval. (Rules 26.2, 74.23 and 103)
35. Within 90 days after the completion of the commissioning period for the combustion turbine, the permittee shall conduct an Initial Emissions Source Test at the exhaust of the turbine to determine the ammonia (NH₃) emission concentration to demonstrate compliance with the ammonia concentration limit of this DOC. After the initial source test, the NH₃ emissions source test shall be conducted on an annual basis.

The source test shall determine the correlation between the heat input rate of the gas turbine, SCR system ammonia injection rate, and the corresponding NH₃ emission concentration at the unit exhaust. NO_x emissions at the CEM shall also be recorded during the test. The source test shall be conducted over the expected operating range of the turbine (including, but not limited to, minimum and full load modes) to establish

the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The permittee shall repeat the source testing on an annual basis thereafter. Ongoing compliance with the ammonia emission concentration limit shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The permittee shall submit the source test results to the District within 45 days of conducting tests. (Rules 26.2, 29, and 74.23)

36. Within 90 days after the completion of the commissioning period for the combustion turbine, the permittee shall conduct an Initial Emissions Source Test at the exhaust of the turbine to demonstrate compliance with the ROC, NO_x, PM₁₀, and CO emission limits of this DOC. The source test shall be conducted over the expected operating range of the turbine including, but not limited to, minimum and full load modes. This source test shall demonstrate compliance with the following short term emission limits during normal operation: ROC = ppmvd @ 15% O₂ and pounds per hour, NO_x = ppmvd @ 15% O₂ and pounds per hour, PM₁₀ = pounds per hour, and CO = ppmvd @ 15% O₂ and pounds per hour. The permittee shall submit the source test results to the District within 45 days of conducting tests.

After the initial source test, the ROC, NO_x, PM₁₀, and CO emissions source test shall be conducted on an annual basis. (Rules 26.2, 29, and 74.23)

37. The District must be notified 30 days prior to any source test, and a source test plan must be submitted for approval no later than 30 days prior to testing. Unless otherwise specified in this permit or authorized in writing by the District, within 45 days after completion of a source test or RATA performed by an independent source test contractor, a final test report shall be submitted to the District for review and approval. (Rule 102)

38. The following source test methods shall be used for the initial and annual compliance verification:

ROC: EPA Methods 18 or 25,
NO_x: EPA Methods 7E or 20,
PM₁₀: EPA Method 5 (front half and back half) or EPA Method 201A,
CO: EPA Methods 10 or 10B,
O₂: EPA Methods 3, 3A, or 20,
Ammonia (NH₃): BAAQMD ST-1B.

EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. (Rules 26, 29, and 74.23 and 40 CFR Part 60 Subpart KKKK)

39. An initial and annual source test and a periodic NO_x and CO Relative Accuracy Test Audit (RATA) shall be conducted on the CTG and its CEM to demonstrate compliance with the NO_x and CO emission standards of this permit and applicable relative accuracy requirements for the CEMS systems using District approved methods. The annual source test and the NO_x and CO RATAs shall be conducted in accordance with

the applicable RATA frequency requirements of 40 CFR75, Appendix B, Sections 2.3.1 and 2.3.3. The initial and annual RATA may be conducted during the initial and annual emission source tests required above and shall be conducted in accordance with a protocol complying with all the applicable requirements of an approved source test protocol. (Rule 74.23 and 103, 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75)

40. Relative Accuracy Test Audits (RATAs) and all other required certification tests shall be performed and completed on the NO_x CEMS in accordance with applicable provisions of 40 CFR Part 75 Appendix A and B and 40 CFR Part 60 Subpart KKKK; and on the CO CEMS in accordance with applicable provisions of 40 CFR Part 60 Appendix B and F. (Rules 74.23 and 103, 40 CFR Part 60 Subpart KKKK, 40 CFR Part 60, and 40 CFR Part 75)
41. The permittee shall maintain hourly records of NO_x, CO, and NH₃ emission concentrations in ppmvd @15% oxygen. NO_x and CO concentrations are measured by the CEM; NH₃ emission concentrations are determined and demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of the ammonia injection rate as required above and below. The permittee shall maintain records of NO_x and CO emissions in pounds per hour, tons per month, and tons per rolling 12 month periods. (Rules 26.2 and 29)
42. The permittee shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown, unplanned load change or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 103, and emission measurements. (Rules 74.23 and 103)
43. The APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the monitoring devices required by this permit to ensure that such devices are functioning properly. (Rule 103)
44. The permittee shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, amount of natural gas consumed, and duration of each start-up, each shutdown, and each unplanned load change time period. (Rules 26 and 74.23)
45. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. (Rules 33 and 103)
46. For purposes of determining compliance with emission limits based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on a Continuous Emission Monitoring System (CEMS), data collected in accordance with the CEMS protocol shall be used and the averages for averaging periods specified herein shall be calculated as specified in the CEMS protocol. (Rules 26.2 and 74.23)

47. For purposes of determining compliance with emission limits based on CEMS data, all CEMS calculations, averages, and aggregates shall be performed in accordance with the CEMS protocol approved in writing by the District. (Rules 26, 74.23, and 103)
48. The number of annual operating hours (including startup and shutdown) for the CTG shall not exceed 2,150 hours per year. The number of startup periods occurring shall not exceed 200 per year. The number of shutdown periods occurring shall not exceed 200 per year.

The CTG shall be equipped with an operating, non-resettable, elapsed hour meter. The permittee shall maintain a log that differentiates normal operation from startup operation and shutdown operation. These hours of operation records shall be compiled into a monthly total. The monthly operating hour records shall be summed for the previous 12 months and reported to the District on an annual basis. (Rules 26 and 74.23)

49. Not later than 90 calendar days prior to the start of construction, the permittee shall submit to the District the final selection, design parameters and details of the selective catalytic reduction (SCR) and oxidation catalyst emission control systems for the CTG including, but not limited to, the minimum ammonia injection temperature for the SCR; the catalyst dimensions and volume, catalyst material, catalyst manufacturer, space velocity and area velocity at full load; and control efficiencies of the SCR and the oxidation catalyst CO at temperatures between 100 °F and 1000 °F at space velocities corresponding to 100% and 25% load. (Rules 26.2 and 74.23)
50. Continuous monitors shall be installed on SCR system prior to their initial operation to monitor or calculate, and record the ammonia solution injection rate in pounds per hour and the SCR catalyst temperature in degrees Fahrenheit for each unit operating minute. The monitors shall be installed, calibrated and maintained in accordance with a District approved protocol, which may be part of the CEMS protocol. This protocol, which shall include the calculation methodology, shall be submitted to the District for written approval at least 90 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when the turbine is in operation. (Rules 26 and 103)
51. Except during periods when the ammonia injection system is being tuned or one or more ammonia injection systems is in manual control for compliance with applicable permit conditions, the automatic ammonia injection system serving the SCR system shall be in operation in accordance with manufacturer's specifications at all times when ammonia is being injected into the SCR system. Manufacturer specifications shall be maintained on site and made available to District personnel upon request. (Rules 26 and 74.23)
52. The concentration of ammonia solution used in the SCR ammonia injection system shall be less than 20% ammonia by weight. Records of ammonia solution concentration shall be maintained on site and made available to District personnel upon request. (40 CFR Part 68)

53. A continuous emission monitoring system (CEMS) shall be installed and operated on the CTG and properly maintained and calibrated to measure, calculate, and record the following, in accordance with the District approved CEMS protocol:
- a. Hourly average concentration of oxides of nitrogen (NO_x) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the NO_x limits of this permit;
 - b. Hourly average concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the CO limits of this permit;
 - c. Percent oxygen (O₂) in the exhaust gas averaged over each operating hour;
 - d. Hourly mass emissions of oxides of nitrogen (NO_x) calculated as NO₂, in pounds;
 - e. Cumulative mass emissions of oxides of nitrogen (NO_x) calculated as NO₂ in each startup and shutdown period, in pounds;
 - f. Daily mass emissions of oxides of nitrogen (NO_x) calculated as NO₂, in pounds;
 - g. Calendar monthly mass emissions of oxides of nitrogen (NO_x) calculated as NO₂, in pounds;
 - h. Rolling 1-hour average and rolling 4-hour concentration of oxides of nitrogen (NO_x) corrected to 15% oxygen, in parts per million (ppmvd);
 - i. Rolling 1-hour average oxides of nitrogen (NO_x) calculated as NO₂ emission rate, in pounds per megawatt-hour (MWh);
 - j. Calendar month, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NO_x), in tons;
 - k. Hourly mass emissions of carbon monoxide (CO), in pounds;
 - l. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
 - m. Daily mass emissions of carbon monoxide (CO), in pounds;
 - n. Calendar monthly mass emissions of carbon monoxide (CO), in pounds;
 - o. Calendar month, calendar year, and rolling 12-calendar-month period mass emissions of carbon monoxide (CO), in tons;
 - p. Average concentration of oxides of nitrogen (NO_x) and carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), averaged over each unit operating hour;
 - q. Average emission rate in pounds per hour of oxides of nitrogen (NO_x) calculated as NO₂ and pounds per hour of carbon monoxide (CO) during each unit operating hour.
54. No later than 90 calendar days prior to initial startup of the CTG, the permittee shall submit a CEMS protocol to the District, for written approval that shows how the CEMS will be able to meet all of the monitoring requirements of this permit. (Rules 74.23 and 103)
55. When the CEMS is not recording data and the CTG is operating, hourly NO_x emissions for purposes of rolling 12-calendar-month period emission calculations shall be determined in accordance with 40 CFR 75 Subpart C. Additionally, hourly CO emissions for rolling 12- calendar-month period emission calculations shall be determined using CO emission factors to be determined from source test emission

factors, recorded CEMS data, and fuel consumption data, in terms of pounds per hour of CO for the gas turbine. Emission calculations used to determine hourly emission rates shall be reviewed and approved by the District, in writing, before the hourly emission rates are incorporated into the CEMS emissions data. (Rules 26.2 and 29)

56. The CTG shall be equipped with continuous monitors to measure, calculate, and record unit operating days and hours and the following operational characteristics and operating parameters (Rule 74.23):

- a. Date and time;
- b. Natural gas flow rate to the CTG during each unit operating minute, in standard cubic feet per hour;
- c. Total heat input to the combustion turbine based on the natural gas higher heating value (HHV) during each unit operating minute, in Million British Thermal Units Per Hour (MMBTU/Hr);
- d. Higher heating value (HHV) of the fuel on an hourly basis, in Million British Thermal Units Per Standard Cubic Foot (MMBTU/SCF);
- e. Stack exhaust gas temperature during each unit operating minute, in degrees Fahrenheit;
- f. Combustion turbine energy output during each unit operating minute in megawatts hours (MWh)

57. The values of these operational characteristics and parameters shall be reduced to hourly averages. The monitors shall be installed, calibrated, and maintained in accordance with a turbine operation monitoring protocol, which may be part of the CEMS protocol, approved by the District, which shall include any relevant calculation methodologies. The monitors shall be in full operation at all times when the combustion turbine is in operation. Calibration records for the continuous monitors shall be maintained on site and made available to the District upon request. (Rule 74.23)

58. At least 90 calendar days prior to initial startup of the CTG, the permittee shall submit a CTG operating parameter monitoring protocol to the District for written approval. This may be part of the CEMS protocol.

59. Thirty (30) calendar days after the end of the commissioning period for the CTG, the permittee shall submit a written report to the District. This report shall include, a minimum, the date the commissioning period ended, the startup and shutdown periods, the emissions of NO_x and CO during startup and shutdown periods, and the emissions of NO_x and CO during steady state operation. This report shall also detail any CTG or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the commissioning period. All of the following continuous monitoring information shall be reported and averaged over each hour of operation, except for cumulative mass emissions. (Rules 26.2 and 29):

- a. Concentration of oxides of nitrogen (NO_x) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);

- b. Concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
- c. Percent oxygen (O₂) in the exhaust gas;
- d. Mass emissions of oxides of nitrogen (NO_x) calculated as NO₂, in pounds and tons;
- e. Cumulative mass emissions of oxides of nitrogen (NO_x) calculated as NO₂ in each startup and shutdown period, in pounds and tons;
- f. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds and tons;
- g. Mass emissions of carbon monoxide (CO), in pounds and tons;
- h. Total heat input to the combustion turbine based on the fuel's higher heating value, in Million British Thermal Units Per Hour (MMBTU/Hr);
- i. Higher Heating Value (HHV) of the natural gas fuel on an hourly basis, in Million British Thermal Units Per Standard Cubic Foot (MMBTU/SCF);
- j. Gross electrical power output of the CTG, in megawatts hours (MWh) for each hour;
- k. SCR catalyst temperature, in degrees Fahrenheit.

60. Upon request of the APCO, the hourly average information required by this permit shall be submitted in writing and /or in an electronic format approved by the District. Upon request of the APCO, the minute-by-minute information required by this permit shall be submitted in an electronic format approved by the District. (Rules 26.2, 74.23, and 103)

61. The CTG shall comply with 40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units. As defined by the annual hours of operation limits, and the natural gas fuel only requirements, of this permit, the CTG is subject to a CO₂ emission standard of 120 lb CO₂ per MMBTU, averaged over a 12 operating month rolling average.

To verify compliance with this condition, as required above by this permit, the permittee shall record and maintain written monthly records of the CTG natural gas consumption and the CTG net electrical sales supplied to the utility grid.

Puente Power Project 779 BHP Tier 4-Final Emergency Diesel Engine

The Emergency Diesel Engine is simultaneously subject to the emission limits, monitoring requirements, and recordkeeping and reporting requirements of the following rules and regulations:

Rule 26.2, New Source Review – Requirements

Rule 74.9, Stationary Internal Combustion Engines

Title 17, California Code of Regulations, Section 93115, Airborne Toxic Control Measure For Stationary Compression Ignition (CI) Engines (ATCM)

40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS IIII)

The following conditions describe and streamline the most stringent requirements of the above rules and regulations. The Ventura County APCD has been delegated authority for 40 CFR Part 60 Subpart IIII and is considered to be the Administrator.

Compliance with the terms of the streamlined conditions below for the Puente Power Project 779 BHP Tier 4-Final Emergency Diesel Engine assures compliance with all individual requirements applicable to the Emergency Engine which have been addressed above and below.

1. The annual hours of operation for maintenance and readiness testing of the 779 BHP Emergency Diesel Engine shall not exceed 50 hours per year. This limit does not include emergency operation when electrical grid power line service has failed. When not being operated for maintenance or readiness testing, the emergency engine shall only be used during a failure or loss of all or part of normal electrical power service to the facility.

The engine shall be equipped with an operating, non-resettable, elapsed hour meter. The permittee shall maintain a log that differentiates operation during maintenance and testing from operation during emergency use. These hours of operation records shall be compiled into a monthly total. The monthly operating hour records shall be summed for the previous 12 months and reported to the District after every calendar year by February 15. (Rule 74.9 and ATCM)

2. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight shall be used to fuel the Emergency Diesel Engine. (ATCM)
3. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which are as dark or darker in shade as that designated as No. 1 on the Ringelmann Chart as published by the United States Bureau of Mines, or 20% opacity. (Rule 50)

4. The emergency engine shall be EPA-certified to the applicable emissions requirements for emergency engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, based on the power rating of the engine and the engine model year. The ROC, NO_x, and PM₁₀ emission limits below have been applied as BACT pursuant to Rule 26.2 and are more stringent than this condition. (Rule 26.2, ATCM, and NSPS IIII)
5. ROC emissions shall not exceed the EPA Tier 4-Final Standard for NMHC of 0.14 g/bhp-hr. The permittee shall maintain documentation certifying that the emergency diesel engine meets this emission standard. (Rule 26.2)
6. NO_x emissions shall not exceed shall not exceed the EPA Tier 4-Final Standard for NO_x of 0.50 g/bhp-hr. The permittee shall maintain documentation certifying that the emergency diesel engine meets this emission standard. (Rule 26.2)
7. PM₁₀ emissions from the engine shall not exceed shall not exceed the EPA Tier 4-Final Standard for PM of 0.02 g/hp-hr. The permittee shall maintain documentation certifying that the emergency diesel engine meets this emission standard. (Rules 26.2 and 51)
8. CO emissions shall not exceed shall not exceed the EPA Tier 4-Final Standard for CO of 2.6 g/bhp-hr. The permittee shall maintain documentation certifying that the emergency diesel engine meets this emission standard. (ATCM and NSPS IIII)
9. The exhaust stack of the Emergency Diesel Engine shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. A flapper type rain cap that is open while the engine is operating may be used. (Rule 51)
10. The Emergency Diesel Engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. (ATCM and NSPS IIII)
11. Permittee shall monitor the operational characteristics of the engine as recommended by the engine manufacturer or emissions control system supplier. (ATCM and NSPS IIII)
12. The existing 154 BHP emergency fire pump engine and 201 BHP emergency generator engine at the Mandalay Generating Station shall be removed prior to operation of this new 779 BHP Emergency Diesel Engine. (Rules 26.2)