VENTURA COUNTY APCD
PRELIMINARY DETERMINATION OF COMPLIANCE

MISSION ROCK ENERGY CENTER
CEC APPLICATION FOR CERTIFICATION DOCKET NUMBER 15-AFC-02

Facility Name:	Mission Rock Energy Center
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VCAPCD Application:	Rule 26.9 - DOC/Authority to Construct No. 08308-100
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I. Project Proposal and Project Summary

The Mission Rock Energy Center (MREC), owned by Mission Rock Energy Center, LLC (MREC, LLC), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of five GE LM6000-PG-Sprint simple-cycle natural gas fired combustion turbine generators (CTG) with a total combined nominal ISO rating of 275 MW, and a new emergency diesel engine powering a fire water pump with a rating of 220 BHP. The new turbines and the new emergency diesel fire water pump engine, along with other ancillary equipment, will be called the Mission Rock Energy Center (MREC). MREC will be located at a new facility near, and to the southwest of, the city of Santa Paula, CA.

This DOC is being issued pursuant to VCAPCD Rule 26.9, New Source Review - Power Plants. MREC is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. MREC filed an Application For Certification (AFC) with the CEC on December 31, 2015 (AFC Docket No. 15-AFC-02).

MREC will be a new major stationary source subject to VCAPCD Rule 33, Part 70 Permits, and a new acid rain source subject to VCAPCD Rule 34, Acid Deposition Control. As required by VCAPCD Rule 33.5, Part 70 Permits - Timeframes for Applications, Review and Issuance, prior to operation of the new CTG's and emergency diesel engine, MREC will submit an application for a Part 70 (Title V) Permit and Title IV Acid Rain Permit.

As shown in this DOC, if fully completed as proposed, the nitrogen oxides (NOx) emissions increase from this project has been calculated to be 28.13 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 36.57 tons per year.

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)
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 for 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). The turbines are 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.” The toxic emissions from the proposed stationary source has combined total HAPs (Hazardous Air Pollutants) emissions of less than 3 tons per year, which is significantly below the major source threshold for a single HAP of 10 tons per year or combined HAPs of 25 tons per year. Note that the Federal Clean Air Act does not define ammonia and sulfuric acid as HAPs. See Appendix H - Hazardous Air Pollutant Potential to Emit.

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 Mission Rock Energy Center (MREC) will be located at 1025 Mission Rock Road near Santa Paula, CA.

IV. Process Description

The Mission Rock Energy Center, LLC (MREC, LLC), requests a Determination of Compliance (DOC) from the Ventura County Air Pollution Control District (VCAPCD) for the installation of five (5) new GE LM6000 Class simple-cycle natural gas fired combustion turbine generators (CTG) and one new emergency diesel fire water pump engine. The new turbines and the new diesel engine along with other ancillary equipment will be called the Mission Rock Energy Center (MREC).

V. Equipment Listing

Five (5) New Combustion Turbine Generators (CTGs):
GE LM6000-PG-Sprint Combustion Turbine Generator (CTG) set, each rated at a nominal 55 MW, simple cycle, single annular combustor with water injection, a Selective Catalytic Reduction (SCR) system with aqueous ammonia injection for nitrogen oxides (NOx) control and an oxidation catalyst for reactive organic compounds (ROC) and carbon monoxide (CO) control.

The GE Sprint (SPRay INTercooling) option includes a combustion air cooling system to increase the power output of the gas turbine by cooling the combustion air, resulting in a higher mass flow through the turbine. MREC will also use an evaporative cooling tower system (also known as a wet surface air condenser / air chiller) to cool the inlet combustion air.

The turbines are simple-cycle turbines; there are no heat recovery steam generators or exhaust cooling towers in this project. The proposed units are GE Model LM6000-PG-Sprint combustion turbine generators. The turbines are designed to fire natural gas only. The net heat rate is 10,142 BTU/kWh (HHV). There are no bypass stacks. The single annular combustor and water injection system achieve lower NOx emissions by lowering the charge temperature with water injection. The exhaust is then sent through an oxidation catalyst and SCR system to further reduce emissions. The oxidation catalyst and SCR system will be sized so that the emissions from each turbine meet the permitted emission limits. The continuous emission monitoring systems, for NOx and CO, will monitor and record the exhaust emission concentrations from each turbine.

Continuous Emission Monitoring System:
A Continuous Emissions Monitoring System (CEMS) is proposed for monitoring and recording NOx and CO emissions from each turbine.

Emergency Internal Combustion Engine:
The project also includes an emergency internal combustion engine. The engine is diesel-fired and will power an emergency fire water pump. The proposed engine is a 220 BHP John Deere diesel engine, certified to meet U.S. EPA and California Air Resources Board emission standards for stationary direct-drive diesel fire pump engines. The engine will be used during emergency operations for the pumping of water for fire suppression or protection. 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 inlet combustion air cooling towers, electric-powered fuel gas compressor, a nominal 100 MWhr (25 MW at 4 hours) battery storage system, water storage tanks, transformers, and one aqueous ammonia storage tank. A "black-start" emergency diesel electricity generating engine is not required because of the battery storage system. This support 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's will use an evaporative water cooling tower system that reduces the inlet combustion air temperature. The CTG's will also be equipped with annular combustors and water injection. The demineralized water injection system will control the formation of pollutants by reducing the combustion temperatures. These combustors will achieve a NOx emission rate of 25 ppmvd @ 15% O_2 using water injection (prior to add-on emissions control).

Each of the proposed CTG's also will be equipped with an oxidation catalyst for ROC and CO control, and a selective catalytic reduction (SCR) system for NOx control. The specific manufacturer(s) will be determined at a later date.

During normal operation, the exhaust from each of the CTGs 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 (CO_2) and water (H_2O). The oxidation catalyst units normally have minimum and maximum operating temperatures of 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 SCR system consists of ammonia injection in the CTG exhaust upstream of the catalyst and a catalyst bed. The ammonia mixes with the exhaust gas and reacts with NOx on the surface and interior of the catalyst to produce nitrogen gas (N_2) and water (H_2O). 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 NOx emissions by approximately 90% from 25 ppmvd to 2.5 ppmvd @ 15% O2.

The proposed emergency diesel internal combustion engine will be certified to meet U.S. EPA and California Air Resources Board emission standards for stationary direct-drive diesel fire pump engines.

VII. Emission Calculations

The emission calculations below are performed pursuant to the requirements of Rule 26.6, New Source Review - Calculations. Based on Rule 26, New Source Review; Rule 29, Conditions on Permits; and Rule 42, Permit Fees; the emissions of reactive organic compounds (ROC), nitrogen oxides (NOx), particulate matter (PM_{10}), sulfur oxides (SOx), carbon monoxide (CO), and ammonia (NH3) have been calculated in the units of tons per year and pounds per hour for the MREC CTG's and emergency diesel fire water pump engine.

Assumptions:

- Applicant has provided turbine manufacturer (GE) performance emission rates for the turbines (see Tables VII-1 & VII-2). These emission rates will be used to calculate total turbine emissions.

- The worst case hourly emissions will be based on turbine performance data (Run 1) of the manufacturer provided data. See Appendix A.

- The annual emissions will be based on the turbine performance data (Run 14) of the manufacturer provided data. See Appendix A.

- MREC will have an annual emission limit for all pollutants that is based on 2,500 total hours of operation for each of the 5 turbines.

- Annual per-turbine emissions = 150 startups (75 hours of operation) + 150 shutdowns (22.5 hours of operation) + 2,402.5 hours steady state (Run 14 emission factors) = 2,500 hours of operation per year per turbine.

- Startup and shutdown pounds per hour (lb/hr) are based on provided emission data (Application Appendix Table 5.1A-1) See Appendix B.

- Natural gas fuel sulfur limit = 0.75 grain per 100 scf, as BACT.

- Higher Heating Value (HHV) of natural gas fuel = 1,021 BTU/scf.

- Annual average operation = 2,804 MMBTU/Hr heat input for all 5 turbines combined (Run 14) = 560.8 MMBTU/Hr per turbine. See Appendix A.

- Worst-case hour heat input = 2,831 MMBTU/Hr for all 5 turbines combined (Run 1) = 566.2 MMBTU/Hr per turbine. See Appendix A.

- Worst-case hour is 30 minutes startup/30 minutes normal operation for NOx, PM10, SOx, CO, NH3. For ROC the worst case hour is 9 minutes shutdown/51 minutes normal operation.

- All ROC NOx, CO, PM10, NH3 emissions in pounds per hour (lbs/hr), emission factor, and ppmvd values are provided by the applicant and turbine manufacturer. Emission factors are calculated using location specific performance data. See Appendix A.

- NOx hourly emission limits are based on the assumption that for the turbines the hourly rate is based on the BACT limit of 2.5 ppmvd NOx. Based on manufacturer data, turbine emissions during steady-state normal ISO operations will be lower. Therefore, the applicant has proposed that annual NOx permitted emissions be calculated based on an average of 2.0 ppmvd NOx. NOx actual emissions in tons per year from the turbines will be tracked with a continuous emissions monitor to ensure that NOx annual permitted emissions are not exceeded.

- ROC lb/hr emissions limits are proposed by the applicant based on manufacturer performance data. The lb/hr limit is equal to approximately 1 ppmvd ROC. This is below the BACT limit of 2 ppmvd ROC.

- SOx emissions are based on the fuel sulfur content. As a BACT limit, 0.75 grains /100 scf will be used in calculating the SOx emissions. The calculation is shown below.

  SOx calculation:

  SOx = (0.75 gr/100 scf) x (1 scf/1,021 BTU) x (lb/7,000 gr) x (2 mol SO2/1 mol S) x (1,000,000 BTU/MMBtu)

  = 0.002098 lb SOx/MMBtu

  SOx lb/hr are calculated by multiplying the turbine heat input by the calculated emission factor and are shown in Tables VII-1 & VII-2 below.

<u>Rule 26.6 B – Potential to Emit</u>

New Combustion Turbine Generators (CTG):
The CTG's have various states of operation: startup, shutdown, normal operation cold day, and normal operation average day. The CTG's have different emission factors associated with the various states of operation. MREC has provided manufacturer emissions data for each of the aforementioned states of operation see Tables VII-1 to VII-3 below.

Combustion Turbine Generator (CTG) Hourly Emission Calculations:
The turbine hourly emissions are calculated using the applicant/manufacturer provided performance data. The worst case hourly emissions occur on a cold day (Table VII-1). The annual emissions from the turbines are calculated using the emissions from the turbines during the average day (Table VII-2).

Table VII-1

Maximum Hourly Operation (cold day performance) - Per Turbine			
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 566.2 MMBTU/Hr*)**
ROC	0.00126 lb/MMBTU	1.0 ppmvd (applicant proposed)	0.71
NO_x	0.00901 lb/MMBTU	2.5 ppmvd (BACT)	5.10
PM_{10}	2.00 lb/hr	2.0 lb/hr (applicant proposed)	2.00
SO_x	0.002098 lb/MMBTU	0.75 grain (BACT)	1.19
CO	0.00877 lb/MMBTU	4.0 ppmvd (applicant proposed)	4.97
NH_3	0.00667 lb/MMBTU	5.0 ppmvd (BACT)	3.78

*From Appendix A Turbine Performance Emissions Data Run 1 plant heat input 2,831 MMBtu/hr / 5 turbines = 566.2 MMBTU/Hr per turbine.

Table VII-2

Average Hourly Operation (ISO conditions performance) - Per Turbine			
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 560.8 MMBTU/Hr*)**
ROC	0.0012558 lb/MMBTU	1.0 ppmvd (applicant proposed)	0.70
NO_x	0.0072 lb/MMBTU	2.0 ppmvd (applicant proposed)	4.04
PM_{10}	2.00 lb/hr	2.0 lb/hr (applicant proposed)	2.00
SO_x	0.002098 lb/MMBTU	0.75 grain (BACT)	1.18
CO	0.00877 lb/MMBTU	4.0 ppmvd (applicant proposed)	4.92
NH_3	0.00667 lb/MMBTU	5.0 ppmvd (BACT)	3.74

*From Appendix A Turbine Performance Emissions Data Run 14 plant heat input 2,804 MMBtu/hr / 5 turbines = 560.8 MMBTU/Hr per turbine.

The maximum startup and shutdown hourly emissions are calculated using the Appendix B startup/shutdown emissions and the remaining time in one hour as normal emissions from the cold day (Performance Run 1). Therefore, an hour when a startup occurs is 30 minutes startup emissions and 30 minutes normal operation. An hour when a shutdown occurs is 9 minutes of shutdown emissions and 51 minutes of normal emissions. These occurrences are shown in Table VII-3 below.

Table VII-3

Startup and Shutdown Hourly Emissions (pounds = lbs) Per Turbine						
Pollutant	**Startup Emissions**			**Shutdown Emissions**		
	Startup	**Normal Operation***	**Maximum Hourly Startup**	**Shutdown**	**Normal Operation***	**Maximum Hourly Shutdown**
Duration (min)	30	30	**60**	9	51	**60**
ROC	1.00	0.36	**1.36**	1.00	0.60	**1.60**
NOx	9.10	2.55	**11.65**	1.20	4.34	**5.54**
PM_{10}	1.00	1.00	**2.00**	0.30	1.70	**2.00**
SOx	0.595	0.595	**1.19**	0.18	1.01	**1.19**
CO	5.50	2.49	**7.99**	1.80	4.23	**6.03**
NH3	1.89	1.89	**3.78**	0.57	3.21	**3.78**

* Table VII-1 Max hourly operation lb/hr emissions divided by listed duration either 30 or 51 minutes, respectively

Maximum hourly emissions can be defined as occurring during any one hour time period where the turbine is in startup mode, the turbine is in shutdown mode, or the turbine is in normal operation. This occurs during a startup hour on a cold day for NOx, PM10, SOx, CO, and NH3. This occurs during shutdown for ROC. During startups and shutdowns the SCR system and the oxidation catalyst are not as effective at reducing NOx, ROC, and CO emissions as the exhaust temperature is not high enough for effective emissions control.

See the table below for the maximum hourly emissions for the turbines.

Table VII-4

Maximum Hourly Emissions (pounds = lbs)		
Pollutant	**Maximum Hourly Per Turbine**	**Maximum Hourly x 5 Turbines (lbs/hr)**
ROC	**1.60**	**8.00**
NOx	**11.65**	**58.25**
PM_{10}	**2.00**	**10.00**
SOx	**1.19**	**5.95**
CO	**7.99**	**39.95**
NH3	**3.78**	**18.90**

Combustion Turbine Generator (CTG) Annual Emission Calculations:

MREC has proposed operation limits for the facility on a per turbine basis of 150 startups (75 hours), 150 shutdowns (22.5 hours), and 2,402.5 hours of normal full load operation on an annual basis. Annual turbine emissions are calculated based on the average hourly operation lb/hr for 2,402.5 hours and the startup and shutdown emissions associated with 150 startups and 150 shutdowns per year. Each turbine is expected to have a maximum of 150 startups and 150 shutdowns per year, with the rest of the hours running normal operation.

Normal operations are expected to occur 2,402.5 hours per year. See emission factors, emission factor basis, and the pounds per hour emissions at the steady state normal operational load below.

Table VII-5

Normal Operation Emissions - Per Turbine				
Pollutant	**Emission Factor**	**Emission Factor Basis**	**Pounds Per Hour (@ 560.8 MMBtu/hr)**	**Tons Per Year (2402.5 hr/yr)**
ROC	0.0012558 lb/MMBTU	1 ppmvd (app proposed)	0.70	0.84
NOx	0.0072 lb/MMBTU	2.0 ppmvd (app proposed)	4.04	4.85
PM_{10}	2.00 lb/hr	2.0 lb/hr (app proposed)	2.00	2.40
SOx	0.002098 lb/MMBTU	0.75 grain, BACT	1.18	1.42
CO	0.00877 lb/MMBTU	4.0 ppmvd (app proposed)	4.92	5.91
NH3	0.00667 lb/MMBTU	5.0 ppmvd, BACT	3.74	4.49

Table VII-6

Startup and Shutdown Annual Emissions				
Pollutant	**Startup**		**Shutdown**	
	Pounds Per Startup	Tons Per Year (150 Startups/yr)	Pounds Per Shutdown	Tons Per Year (150 Shutdowns/yr)
ROC	1.00	0.075	1.00	0.075
NOx	9.10	0.68	1.20	0.09
PM_{10}	1.00	0.075	0.30	0.023
SOx	0.595	0.045	0.18	0.0135
CO	5.50	0.4125	1.80	0.135
NH3	1.89	0.14175	0.57	0.04275

Table VII-7

Maximum Annual Emissions					
Pollutant	**Annual Startups**	**Annual Shutdowns**	**Annual Normal Operation**	**Total Annual Turbine Operation**	**Annual x 5 Turbines**
	Tons Per Year	Tons Per Year	Tons Per Year	Tons Per Year	Tons Per Year
ROC	0.075	0.075	0.84	**0.99**	**4.95**
NOx	0.68	0.09	4.85	**5.62**	**28.10**
PM_{10}	0.075	0.023	2.40	**2.50**	**12.50**
SOx	0.045	0.0135	1.42	**1.48**	**7.40**
CO	0.4125	0.135	5.91	**6.46**	**32.30**
NH3	0.14175	0.04275	4.49	**4.67**	**23.35**

Maximum Annual is 150 startups (75 hours) + 150 shutdowns (22.5 hours) + 2402.5 hours normal operation = 2500 hours total usage.

Table VII-8

Maximum Turbine Emissions Hourly and Annual Operations				
Pollutant	**Hourly**	**Hourly x 5 Turbines**	**Annual***	**Annual x 5 Turbines**
	lb/hr	lb/hr	Tons/yr	Tons/yr
ROC	1.60	8.00	0.99	**4.95**
NOx	11.65	58.25	5.62	**28.10**
PM_{10}	2.00	10.00	2.50	**12.50**
SOx	1.19	5.95	1.48	**7.40**
CO	7.99	39.95	6.46	**32.30**
NH3	3.78	18.90	4.67	**23.35**

* Annual is 150 startups (75 hours) + 150 shutdowns (22.5 hours) + 2402.5 hours normal operation

= 2500 hours total

Turbine Commissioning Emissions:

The turbines must go through a specific set of tests and steps before being certified as operational and available to provide power. The application includes information on the commissioning schedule for the turbines (see Appendix C). The SCR with ammonia injection and oxidation catalyst control systems will not be operable during all of the commissioning period as the control systems are going through a commissioning period as well. These systems do not alter the PM or SOx emissions; therefore, only the ROC, NOx, and CO emissions will be affected.

The turbines will have conditions placed on the permit which limits the facility to only having two turbines in the commissioning phase at any one time. Therefore, the worst case hourly commissioning emissions will be ROC = (2)(3.0) = 6.0 lbs/hr; NOx = (2)(68.0)= 136.0 lbs/hr; and CO = (2)(117.33)= 234.66 lbs/hr. The emissions from the commissioning process will be accounted for in the total annual emissions from the CTG. MREC will ensure that the total annual emissions from the facility do not exceed their annual permitted emissions including during the commissioning process.

Table VII-9

New Turbine Commissioning Emissions- Each Turbine		
Pollutant	**Maximum Commissioning Emissions (lbs/hr)***	**Total Commissioning Emissions (tpy)****
ROC	**3.0**	**0.82**
NOx	**68.0**	**10.33**
CO	**117.33**	**22.14**
SOx	**1.19**	**n/a**
PM10	**2.00**	**n/a**

* Only two turbines will be in the commissioning phase that produces the maximum hourly emission rates (lbs/hr).
**Total commissioning emissions in tons per year (tpy) is for all 5 turbines combined.

Emergency Diesel Fire Pump Engine Emission Calculations:

The permitted emissions for the 220 BHP John Deere emergency diesel fire water pump engine are based on full-load operation at a limit of 50 hours per year for maintenance and readiness testing. The engine will have a 50 hours per year limit for non-emergency usage. There will not be an hours per year limit for actual emergencies for the pumping of water for fire suppression or protection. The emission factors are based on the California ARB Airborne Toxic Control Measure (ATCM) for Stationary Internal Combustion Engines Table 2 standards for new direct-drive fire pump engines of Model Years 2009 and after. The NMHC+NOx standard of 3.0 g/bhp-hr is assumed to be 5% ROC and 95% NOx. The emission factors and permitted emissions are shown below:

Table VII-10

New 220 BHP Emergency Fire Pump Engine Emission Calculations				
Pollutant	**Emission Factor (g/bhp-hr)**	**Emission Factor Basis**	**Pounds Per Hour**	**Tons Per Year (50 hr/yr)**
ROC	0.2	Stationary Engine ATCM fire pump engine standards	0.10	0.00
NOx	2.8	Stationary Engine ATCM fire pump engine standards	1.36	0.03
PM_{10}	0.15	Stationary Engine ATCM fire pump engine standards	0.07	0.00
SOx	0.0051	Very low sulfur fuel (15 ppmw) mass balance see below	< 0.01	0.00
CO	2.6	Stationary Engine ATCM fire pump engine standards	1.26	0.03

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

The facility is a new facility therefore the facility pre-project emissions are zero for all pollutants. The facility post-project emissions are shown below.

Table VII-11

Summary of Facility Post-Project Potential Permitted Emissions (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	**CO**	**NH_3**
Five New Turbines (CTGs)	4.95	28.10	12.50	7.40	32.30	23.35
New 220 BHP Emergency Engine	0.00	0.03	0.00	0.00	0.03	0
Post-Project Total Stationary Source	**4.95**	**28.13**	**12.50**	**7.40**	**32.33**	**23.35**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

As shown above, post-project the facility is a major source for NOx only.

Rule 26.6 C – Actual Emissions:

Actual emissions are the emissions from existing equipment based on its actual operating history. MREC is a new facility. All of the equipment in this project is new. Therefore, the CTGs and emergency fire pump engine have no actual emissions.

Rule 26.6.D – Emission Increases:

Section D.1. of Rule 26.6 defines the emission increase for new emission units as the potential to emit of the new emission units. The CTGs and the emergency diesel fire pump engine are new emission units. Therefore, the emission increases are equal to the potential to emit of the new equipment and are shown in the table below.

Table VII-12

Summary of Facility Emission Increases (Tons Per Year)						
	ROC	**NOx**	**PM_{10}**	**SOx**	**CO**	**NH_3**
Five New Turbines (CTGs)	4.95	28.10	12.50	7.40	32.30	23.35
New 220 BHP Emergency Engine	0.00	0.03	0.00	0.00	0.03	0
Post-Project Total Stationary Source Emission Increase	**4.95**	**28.13**	**12.50**	**7.40**	**32.33**	**23.35**
Rule 26.1: Major Source Thresholds	25	25	N/A	N/A	N/A	N/A

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 (NOx) or reactive organic compounds (ROC).” There are not major source thresholds for PM10, SOx, CO, or NH3.

As shown above the facility will be a Rule 26 major source of NOx after the installation of the five CTGs and emergency fire water pump engine. The facility will not be a Rule 26 major source of ROC.

VIII. Rules Compliance

Rule 26.2 – Section A Best Available Control Technology (BACT)

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 has a zero threshold for BACT for ROC, NOx, PM-10, and SOx. BACT is not required for CO.

BACT is defined in Rule 26.1 as the most stringent emission limitation or control technology for an emission unit which a.) has been achieved in practice, or b.) is contained in an implementation plan approved by EPA, or c.) is contained in any applicable NSPS or NESHAP, or d.) any other limitation or control determined to be technologically feasible and cost effective.

1. **Combustion Turbine Generators (CTGs):**

BACT requirements apply for ROC, NOx, PM-10, and SOx. There are no BACT requirements for CO. Each of the five turbines is designed to be a simple cycle turbine, meaning it employs a “simple power cycle” and no waste heat is recovered for secondary steam production. There are no heat recovery steam generators (HRSGs). 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.

Table VIII-1

EPA RACT/BACT/LAER Natural Gas Simple Cycle Turbine > 25MW				
Date	**Facility**	**NOx**	**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% O2	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 below:

Table VIII-2

SCAQMD BACT >50 MW Turbine			
Date	**SCAQMD Gas Turbine**	**NOx**	**ROC**
10/20/00	Natural Gas Fired, > 50 MW	2.5 ppmvd @ 15% O2, 1 Hr rolling avg. **OR** 2.0 ppmvd @ 15% O2, 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:

Table VIII-3

SCAQMD Site Specific Determinations					
Date	**Project Location**	**Equipment**	**NOx limit**	**ROC limit**	**Comments**
02/10/04	El 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
02/27/08	Walnut Creek Energy Park/ City of Industry, CA	5 – 100 MW GE LMS100	2.5 ppmvd	2.0 ppmvd	High temp SCR/oxidation catalyst
12/01/10	CPV Sentinel, LLC	8 -100 MW GE LMS100	2.5 ppmvd	2.0 ppmvd	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:

Table VIII-4

SJVAPCD BACT Guideline 3.4.7			
Date	**SJVAPCD Gas Turbine**	**NOx**	**ROC**
10/01/02	= or >50 MW, Uniform Load, without Heat Recovery	Achieved in practice: 5.0 ppmvd @15% O2, 3 Hr avg. (high temp SCR) Technologically feasible: 2.5 ppmvd @ 15% O2 (high temp SCR or equal) 3.0 ppmvd @ 15% O2 (high temp SCR or equal)	Achieved in practice: 2.0 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst) Technologically feasible: 0.6 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst) 1.3 ppmvd @15% O2, 3 Hr avg. (oxidation catalyst)

SJVAPCD provides the following site-specific BACT determination:

Table VIII-5

SJVAPCD Site Specific BACT Determination					
Date	**Project/Location**	**Equipment**	**NOx limit**	**ROC limit**	**Comments**
12/19/07	Panoche Energy Center Firebaugh, CA	100 MW GE LMS100, Turbine	2.5 ppmvd (1-Hr avg.)	2.0 ppmvd (3-Hr avg.)	Water injection SCR/oxidation catalyst

BAAQMD: The Bay Area Air Quality Management District determines BACT requirements on a case by case basis. The latest revision to a turbine was done in April 2004. The resulting BACT database includes the following:

Table VIII-6

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 there are the following guidance:

Table VIII-7

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:

NOx:
As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.5 ppmvd NOx @ 15% O2 have been achieved in practice for a simple cycle turbine at many facilities. These levels have been achieved using water injection into the combustors to limit NOx production and an SCR system for NOx control. There have been some facilities with combined cycle turbines that have been permitted at 2.0 ppmvd NOx @ 15% O2 using SCR. However, the VCAPCD is not aware of any simple cycle facilities demonstrating continuous compliance with a 2.0 ppmvd NOx limit. Alternative controls for NOx such as XONON combustors or EMx catalyst have not been demonstrated to be capable of reliably meeting a NOx limit lower than 2.5 ppmvd NOx @ 15% O2 for simple-cycle turbines of this size. No lower emission levels for NOx have been identified as being technologically feasible, contained in an implementation plan or in NSPS or NESHAP. Therefore, BACT for NOx is 2.5 ppmvd @15% O2 (1 hr average).

ROC:
As shown in the BACT guidelines listings above for gas fired turbines, emission levels of 2.0 ppmvd ROC @ 15% O2 have been achieved in practice for a simple cycle turbine. These levels have been achieved using an oxidation catalyst for ROC control. No lower emission levels for ROC are contained in an implementation plan or in NSPS or NESHAP. Therefore, BACT for ROC is 2.0 ppmvd @15% O2 (1 hr average).

PM10 and SOx
BACT for PM10 and SOx will be the use of PUC-regulated natural gas. This is accepted achieved-in-practice BACT by the SCAQMD, SJVUAPCD, and BAAQMD BACT Guidelines. No lower emission levels for natural gas fired turbines for PM10 and SOx have been identified as being technologically feasible, contained in implementation plans or in NSPS or NESHAP. Therefore, BACT for PM10 and SOx is use of PUC regulated natural gas.

In summary, BACT for the proposed simple-cycle GE LM600 gas combustion turbine generators is as follows:

Table VIII-8

BACT Simple Cycle GE LM6000 Gas Combustion Turbine Generators	
NOx	2.5 ppmvd @ 15% O_2, 1 Hr average, SCR
ROC	2.0 ppmvd @ 15% O_2 as methane, 1 Hr average, oxidation catalyst
PM_{10}	PUC-regulated natural gas only
SOx	PUC-regulated natural gas only

2. Emergency Diesel Fire Pump Engine:

Rule 26.2.A BACT requirements apply to ROC, NOx, PM-10, and SOx. Rule 26.2.A does not require BACT for CO emissions. The unit is a 220 BHP diesel-fired emergency fire water pump engine. The engine will have a 50 hours per year limit for non-emergency usage such as maintenance and readiness testing.

Since stationary emergency fire pump engines are regulated by U.S. EPA at the point of manufacture, BACT is considered to be compliance with Table 4 of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines". These engine emission standards are identical to the standards of the California Air Resources Board (CARB) Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This engine is subject to Table 2 of the ATCM as it is considered to be a new direct-drive fire pump engine. As a 220 BHP engine with a model year of 2011 it is subject to the following emission limits: NMHC+NOx = 3.0 g/bhp-hr, PM = 0.15 g/bhp-hr, and CO= 2.6 g/bhp-hr. ROC is assumed to be equivalent to NMHC. In addition, the ATCM also requires the use of CARB low-sulfur diesel fuel with a sulfur content of less than 0.0015% by weight.

Therefore, BACT for the 220 BHP John Deere emergency diesel fire water pump engine is as follows:

Table VIII-9

BACT Emergency Diesel Fire Water Pump Engine	
NOx	CARB Stationary Engine ATCM - NMHC+NOx = 3.0 g/bhp-hr
ROC	CARB Stationary Engine ATCM - NMHC+NOx = 3.0 g/bhp-hr
PM_{10}	CARB Stationary Engine ATCM - PM = 0.15 g/bhp-hr
SOx	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, NOx, PM10, and SOx. Emission offsets are not required for CO or NH3.

The offset thresholds are shown in Rule 26.2.B Table B-1.

Table VIII-10

Rule 26.2.B Table B-1 Offset Thresholds			
Pollutant	**Offset Threshold**	**Facility Post-Project Emissions**	**Offsets Triggered?**
ROC	5.0 ton/yr	4.95 ton/yr	No
NOx	5.0 ton/yr	28.13 ton/yr	Yes
PM_{10}	15.0 ton/yr	12.50 ton/yr	No
SOx	15.0 ton/yr	7.40 ton/yr	No

As shown in the table above, the offset thresholds of Rule 26.2 Table B-1 are exceeded for NOx only. Therefore, offsets will be required for any emission increases in NOx as calculated pursuant to Rule 26.6, New Source Review - Calculations. There are no offsets required for any ROC, PM_{10}, or SOx emission increases as the offset thresholds shown above will not be exceeded.

NOx Offset Requirements – Potential Emission Increases (Rule 26.6.D.1)
The increase in NOx emissions from the proposed five CTGs and emergency fire pump engine will be offset using Emission Reduction Credits (ERCs). The MREC facility is a new source. The emission increase from the new equipment is calculated as the potential to emit for the new emissions units. Therefore, the NOx emissions increase is equal to the post project potential permitted 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 tradeoff ratio

= (5 new CTGs + new emergency engine) x 1.3 offset tradeoff ratio
= (28.10 tons + 0.03 tons) x 1.3 offset tradeoff ratio
= 28.13 tons NOx/yr x 1.3 offset tradeoff ratio
= 36.57 tons NOx/yr

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 the NOx offsets are <u>not</u> required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program, dated April 1, 2017, shows a positive balance for NOx.

The actual ERC certificates will be identified prior to the issuance of the Final Determination of Compliance (FDOC). VCAPCD will not issue the FDOC until the ERC's have been identified and evaluated. In addition, the VCAPCD will provide a public notice of the proposed ERC's prior to the issuance of the FDOC. This public notice will specify a 45-day public comment period for the proposed ERCs.

Rule 26.2 B. 4 Offsets - ERC Quarterly Profile Check

As discussed above, the ERC Certificates will be identified prior to the FDOC being issued. VCAPCD will perform a quarterly profile check once the ERCs have been identified.

The applicant must provide the proposed quarterly profile of Mission Rock Energy Center to show that it meets the quarterly profile check of 80% as required by Rule 26.6.F.

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 MREC 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 MREC will result in an increase in NOx emissions over the 15.0 tons per year threshold and therefore a public notice will be required. The notification shall be published in a newspaper of general circulation in Ventura County. The notice period shall provide at least 30 days for the public to submit written comments regarding the decision. The VCAPCD shall consider all comments made during the comment period.

The VCAPCD 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 VCAPCD 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 MREC as an Application for Certification has been submitted to the California Energy Commission (Docket No. 15-AFC-02). The VCAPCD conducted a Determination of Compliance review (this document) as required by Rule 26.9. As required by Rule 26.9.F, a public notice and comment period shall be conducted as required by Rule 26.7. Compliance with Rule 26.9 is confirmed.

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

This rule provides for the evaluation by the VCAPCD 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 MREC is required to provide NOx offsets as calculated above, the VCAPCD shall evaluate the proposed offsets pursuant to Rule 26.11 Section B.

Pursuant to Rule 26.2.B.2.d and Rule 26.11.C.6 these NOx offsets are <u>not</u> required to be surplus at the time of use since the most recent report of the Rule 26.11 Annual Equivalency Demonstration Program, dated April 1, 2017, 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, MREC results in being a new major source for NOx only. MREC is a <u>new</u> major source and not a <u>modified</u> source. 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 (Analysis of Alternatives).

<u>Rule 26.13 New Source Review – Prevention of Significant Deterioration</u>

The post-project potentials to emit from all new units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is therefore 250 tons per year (tpy) for any regulated NSR pollutant.

Table VIII-11

PSD Major Source Determination: Potential to Emit (Tons Per Year)						
	NO2	**ROC**	**SO2**	**CO**	**PM**	**PM10**
Total PE from New and Modified Units	28.13	4.95	7.40	32.33	12.50	12.50
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore, Rule 26.13 is not applicable and no further PSD analysis is required.

<u>Rule 29 Conditions On Permits</u>

Section A of this rule requires the VCAPCD 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 VCAPCD 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 have a potential to emit that equals or exceeds the federal major source thresholds are subject to the requirements of Part 70 Permits (commonly called Title V sources) must submit timely applications to apply for their Part 70 Permit. In addition as discussed below, facilities that require a Title IV Acid Rain Permit are also required to obtain a Part 70 (Title V) Permit. MREC is a new facility that will be subject to the Part 70 permit requirements. Therefore, MREC will be required to submit a Part 70 permit application to the VCAPCD prior to operating the new turbines and emergency fire pump engine. A condition has been included in the DOC to ensure that the MREC submits a Part 70 permit application prior to operation of the new turbines and emergency fire pump engine.

Rule 34 Acid Deposition Control

This rule applies to any acid rain source, as defined in Title IV of the 1990 Federal Clean Air Act Amendments. A Title IV Acid Rain permit is required for the proposed turbines because they are new fossil fuel fired combustion devices 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 Rule 34, Acid Deposition Control. The Determination of Compliance will require that MREC submit the Title IV Acid Rain permit application prior to operating the new turbines.

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 turbines, emergency diesel fire pump 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 turbines, emergency diesel fire water pump engine, and ammonia tank, are not expected to create nuisance problems, such as smoke or odors.

The VCAPCD 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 health risks are:

Table VIII-12

RMR Results				
Unit Description	**Cancer Risk**	**Hazard Index**		**Health Risk Reduction Plan Required?**
		Chronic	**Acute**	
Natural Gas Turbines	1.18×10^{-8}	1.66×10^{-5}	3.20×10^{-2}	No
Emergency Diesel Engine	6.76×10^{-6}	1.29×10^{-3}	---	No
Project Total	$\mathbf{6.77 \times 10^{-6}}$	$\mathbf{1.31 \times 10^{-3}}$	$\mathbf{3.20 \times 10^{-2}}$	**No**

The acute and chronic hazard indices are below 0.5 and the cancer risk factor associated with the project is less than 10 in a million. In accordance with VCAPCD's "Air Toxics Review of Permit Application" policy, the project is approved without the need to submit a Health Risk Reduction Plan.

Rule 54 Sulfur Compounds

Rule 54 requires compliance with sulfur dioxide (SO_2) emission limits of 300 ppmv and compliance with ground level concentration limits of SO_2 (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 modeled ground level concentrations of 14.96 $\mu g/m^3$ (0.0114 ppmv) on a 1 hour average and 1.98 $\mu g/m^3$ (0.00151 ppmv) on a 24 hour average. 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 MREC that will assure compliance with this rule. Compliance with this rule is expected during the routine operation of the MREC.

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 2.0 pounds per hour (which is greater than the EPA AP-42 emission factor) and the maximum fuel input rate of 566.2 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 fire pump 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 220 BHP John Deere emergency diesel fired internal combustion engine. The engine will provide emergency firewater capabilities for the protection of life and property. 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 VCAPCD per Rule 74.9.F.2.

Rule 74.23 Stationary Gas Turbines

The proposed gas turbines are subject to the 9 x E/25 ppmvd @ 15% oxygen NOx 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 NOx 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 NOx limit. The required NOx continuous emission monitor will also verify compliance with the NOx emission limit.

The turbines are also subject to the 20 ppmvd ammonia (NH_3) 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 turbines from the NOx and NH_3 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 VCAPCD inspection for 2 years. However, VCAPCD 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 VCAPCD with reports and data identifying the annual usage (e.g., fuel consumptions, operating hours, etc.) of the turbines 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 each of the new GE LM6000 Turbines will be equipped with NOx, 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 VCAPCD has verified that the new turbines and the emergency diesel fire pump 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 Direct-Drive Fire Pump Engines	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. A permit condition will be included in the DOC requiring the use of CARB certified diesel fuel.
The engine(s) must meet the emission standards in Table 2 of the ATCM for the specific power rating and model year of the proposed engine.	The applicant has proposed the use of a diesel fire water pump 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.	A permit condition will be included in the DOC to require that the engine 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.
A non-resettable hour meter with a minimum display capability of 9,999 hours shall be installed upon engine installation, 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.	A permit condition will be included in the DOC to require that the engine be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours.
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 will be included in the DOC.

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 VCAPCD holds no discretionary approval powers over this project; however the VCAPCD 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). An Authority to Construct and 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 VCAPCD makes the following findings regarding this project: the VCAPCD holds no discretionary approval powers over this project and the VCAPCD's actions are ministerial (CEQA Guidelines § 15369).

VCAPCD Rule 13.C.2 requires for projects requiring CEQA review for the VCAPCD 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 220 BHP John Deere emergency diesel fire pump 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 60.402(d) Table 4 applies to manufacturers of emergency fire pump engines.

Section 60.4205 contains emission standards for the engine. Section 60.4205(c) requires owners and operators of fire pump engines to comply with Section 60.402(d) Table 4 for manufacturers as discussed above. For engines in this power range (220 BHP) and 2011 model year, Table 4 requires 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+NOx, CO and PM respectively. The proposed engine complies with these standards as shown in Appendix D – Diesel Engine Performance Data.

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 fire pump 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 LM6000-PG-Sprint gas turbines are subject to the subpart because the heat input for one turbine is 566.2

MMBTU/Hr. Each turbine is a simple cycle turbine without heat recovery. The turbines will be fired on only PUC regulated natural gas.

Section 60.4320 requires turbines to meet the applicable NOx standard in Table 1 of the subpart. The proposed natural gas fired turbines heat input are each 566.2 MMBTU/Hr, therefore the NOx limit as listed in Table 1 is 25 ppmvd at 15% O2 or 1.2 lb/MW-Hr when operating at or above 75% peak load and 96 ppmvd at 15% O2 or 4.7 lb/MW-hr when operating below 75% of peak load.

This Subpart KKKK NOx limit is less stringent than VCAPCD Rule 74.23 limit (9 ppmvd NOx) and the VCAPCD Rule 26.2.A NSR BACT limit of 2.5 ppmvd NOx for the turbines. Therefore, new turbines compliance with the VCAPCD NSR BACT requirements will comply with the Subpart KKKK.

Section 60.4330 requires the turbines to meet the SO_2 emission limits. The turbines will be fired on PUC regulated natural gas therefore the SO_2 emissions limits are either 0.90 lbs- SO_2/MWh discharge based on gross output (Section 60.4330 (a)(1)) or 0.060 lbs-SO_2/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 (0.002098 lbs- SO_2/MMBTU). This sulfur content is lower than the fuel sulfur standard. Therefore, the new turbines 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 operate the turbines in this manner.

Section 60.4335 provides guidance on requirements when water or steam injection is being used to control NOx emissions. The section requires installation, certification, and maintaining of a continuous emission monitoring system (CEMS). The facility has proposed to install and operate a CEMS which will comply with this section.

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 NOx 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. MREC will be required to keep records of fuel 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 NOx emission rate exceeds the applicable standard of 25 ppmvd at 15% O2 (or 96 ppmvd at 15% O2 when operating below 75% peak load as described above). 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 NOx 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 NOx concentration along with EPA Methods 1 and 2 to determine stack gas flow rate or NOx 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 for Electric 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 MREC turbines must meet the table 2 emission standard of 50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO2/MMBTU).

Table 2 of NSPS Subpart TTTT CO2 Emission Standards for Stationary Combustion Turbines	
Affected EGU	**CO2 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 each turbine at MREC 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 each of the new MREC CTG's 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 MREC CTG's would be non-base load units under the final CPS. As non-base load units, under the final CPS the potential electric output for each MREC turbine is calculated as follows:

Potential electric output =

$$= Design\ efficiency\ (\%) \times\ Heat\ Input\ Rate, \frac{MMBtu}{hr} \times \frac{10^6 Btu}{MMBtu} \times \frac{1\ kWh}{3412.1416\ Btu} \times \frac{1\ MWh}{1{,}000\ kWh} \times 8{,}760 hrs/yr$$

$$= 0.41 \times 2{,}831 \frac{MMBtu}{hr} \times \frac{10^6 Btu}{MMBtu} \times \frac{1\ kWh}{3412.1416\ Btu} \times \frac{1\ MWh}{1{,}000\ kWh} \times 8{,}760 hrs/yr$$

$$= 2{,}979{,}893 \text{ MW per year}$$

As long as the new MREC CTG's have net electric sales of less than 0.41 * 7,268,033 MW, or 2,979,893 MW per year, it will be subject to the 120 lb CO_2/MMBTU limit for non-base load gas turbines. The new MREC CTG is expected to operate with an annual capacity factor of approximately 29%. With a full load net nominal output of approximately 275 MW, the MREC units would supply a maximum of approximately 29% x 8760 hrs/year x 275 MW/Hr = 698,610 MW per year to a utility power distribution system. Since this output is less than the allowable level of 2,979,893 MW per year, MREC 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 lb CO_2/MMBTU or less per section 60.5520(d)(1). Therefore, the facility will be required to maintain fuel purchase records of the natural gas.

Compliance with the requirements of 40 CFR Part 60, Subpart TTTT, "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units", is expected.

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

This NESHAP rule applies to the new emergency diesel fire pump 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 NOx, and 100 tons per year for PM, SOx, or CO) for NOx. The turbine will have a continuous emissions monitor (CEMs) 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 NOx 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.

40 CFR Part 75 – Continuous Emission Monitoring (CEMS)

The new turbines combusts only natural gas, they are only required to monitor NOx and CO2 (or O2) and has the choice of monitoring SOx 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

The Mission Rock Energy Center is expected to comply with all applicable VCAPCD, State, and Federal rules and regulations that the VCAPCD implements and enforces. Issue a Rule 26.9 Determination of Compliance for the Mission Rock Energy Center subject to the DOC Conditions presented in Appendix K.

Appendices:

Appendix A	Turbine Performance Emissions Data
Appendix B	Turbine Startup Emissions Data
Appendix C	Commissioning Schedule
Appendix D	Diesel Engine Performance Data
Appendix E	ERCs Identified For Use
Appendix F	ERC Profile Check
Appendix G	Air Quality Impact Analysis and Risk Management Review
Appendix H	Hazardous Air Pollutant Potential to Emit
Appendix I	Certification of Statewide Compliance
Appendix J	Analysis of Alternatives
Appendix K	DOC Conditions

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