1. Introduction

The Bay Area Air Quality Management District (Air District) is issuing a Preliminary Determination of Compliance (PDOC) for the Mariposa Energy Project, a proposed nominal 200-megawatt natural gas fired electric power generation facility that would be located near Byron, CA. The Preliminary Determination of Compliance sets forth the District's preliminary analysis as to how the facility would comply with applicable air quality regulatory requirements, as well as proposed permit conditions to ensure compliance. The Air District is publishing this document for public review and comment, and will review and consider all comments received from the public before deciding whether to issue a Final Determination of Compliance (FDOC) for the proposed project.

The proposed Mariposa Energy Project (MEP) is a simple-cycle "peaker" power plant, meaning that it will be used to meet demand for electrical power during short-term "peaks" in demand. The proposed project consists of four General Electric (GE) LM6000 PC-Sprint simple-cycle gas turbines, a 220 brake horsepower diesel fire pump driver, and associated equipment. The proposed power plant would operate up to 47% of the year depending on the demand for electricity in the region. Pacific Gas and Electric (PG&E) would be responsible for dispatching the plant to meet electrical demand through a power purchase agreement between PG&E and Mariposa Energy LLC (Mariposa). The project utilizes simple-cycle turbines that are designed as a firm supply of power for when renewable energy sources such as wind power are not available. The project will provide standby power capacity for grid stability and the plant is using simple-cycle turbines for this purpose. The simple-cycle turbines are well suited for peaking power plants that may not run for an extended period of time since this type of unit does not have a steam turbine that would need to be kept warm to avoid equipment damage.

The Mariposa Energy Project would be constructed on a 10-acre parcel in the northeastern corner of unincorporated Alameda County. The parcel is south of Kelso Road and east of Bruns Road. I-580 is approximately 3.5 miles to the south and the closest segment of the Byron Highway is approximately 2 miles to the northwest.

Best Available Control Technology and emission offset requirements of the District New Source Review (NSR) requirements are contained in District Regulation 2, Rule 2. This document also includes proposed permit conditions necessary to ensure compliance with applicable rules and regulations, air pollutant emission calculations, and a health risk assessment that estimates the impact of emissions from the project on public health.

This PDOC has been prepared in accordance with District Regulations 2-2-404 through 2-2-406, which set forth the procedural requirements for the issuance of NSR permits, and District Regulations 2-3-403 and 2-3-404, which apply the requirements specifically to power plant permits. This document sets forth the District's reasons and analysis underlying the District's preliminary determination that the project would comply with all applicable regulatory requirements relating to air quality.

The remainder of this document is organized as follows. Section 2 provides an overview of the legal framework for power plant permitting in California and describes how members of the public can learn about the project and provide input to the District and the California Energy Commission.

Section 3 then proceeds to describe the proposed Mariposa Energy Project, and Section 4 details the project's air emissions. Sections 5 and 6 then describe the "Best Available Control Technology" and emission offset requirements for the project and how the proposed facility would comply with them. Section 7 addresses two federal permitting requirements, the "Prevention of Significant Deterioration" requirement and the "Non-Attainment New Source Review" requirement for fine particulate matter, and explains how this facility is not subject to those requirements. Section 8 presents the results of the Health Risk Screening Analysis the District has conducted for the project, which found that the health risks from the project will be less than significant. Section 9 addresses other applicable legal requirements for the proposed project. Section 10 sets forth the proposed permit conditions for the project. Section 11 concludes with the District's PDOC for the project.

2. The Power Plant Permitting Process and Opportunities for Public Participation

The California Energy Commission (Energy Commission or CEC) is the primary permitting authority for new power plants in California. The California Legislature has granted the Energy Commission exclusive licensing authority for all thermal power plants in California of 50 megawatts or more. (See Warren-Alquist State Energy Resources Conservation and Development Act, Cal. Public Resources Code §§ 25000 et seq.) This licensing authority supersedes all other local and state permitting authority. The intent behind this system is to streamline the licensing process for power plants while at the same time providing for a comprehensive review of potential environmental and other impacts.

As the lead permitting agency, the CEC conducts an in-depth review of environmental and other issues posed by the proposed power plant. This comprehensive environmental review is the equivalent of the review required for major projects under the California Environmental Quality Act (CEQA), and the Energy Commission's license satisfies the requirements of CEQA for these projects. This CEQA-equivalent review encompasses air quality issues within the purview of the Air District, and also includes all other types of environmental and other issues, including water quality issues, endangered species issues, and land use issues, among others.

The Air District collaborates with the Energy Commission regarding the air quality portion of its environmental analysis and prepares a "Determination of Compliance" that outlines whether and how the proposed project will comply with applicable air quality regulatory requirements. The Determination of Compliance is used by the Energy Commission to assess air quality issues of the proposed power plant. This document presents the District's Preliminary Determination of Compliance. The District will solicit and consider public input on the Preliminary Determination of Compliance, and then will issue a Final Determination of Compliance for use by the Energy Commission in its CEQA-equivalent environmental review. The CEC will then conduct its environmental review, and at the end of that process it will decide whether to issue a license for the project and under what conditions.

Both the Energy Commission licensing process and the District's Determination of Compliance process relating to air quality issues provide opportunities for public participation. For the District's Determination of Compliance, the District publishes its preliminary determination – the PDOC – and invites interested members of the public to review and comment on it. This public process allows members of the public to review the District's analysis of whether and how the facility will comply with applicable regulatory requirements and to bring to the District's attention any area in which members of the public believe the District may have erred in its analysis. This process helps improve the District's final determination by bringing to the District's attention any areas where interested members of the public disagree with the District's proposal at an early enough stage that the District can correct any deficiencies before making the final determination. The Energy Commission provides similar opportunities for public participation, and publishes its proposed actions for public review and comment before taking any final actions.

At this time, the Air District is at the beginning of this process for the Mariposa Energy Project. The Air District is publishing its Preliminary Determination of Compliance (PDOC) for public review and comment, and will consider comments from the public in determining whether to issue a Final Determination of Compliance (FDOC) and on what basis. The District invites all interested parties to comment in writing on any aspect of the Preliminary Determination of Compliance pursuant to District Regulation 2-2-405. Comments should be made in writing and should be directed to Madhav Patil, Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA 94109, (415) 749-4674, mpatil@baaqmd.gov. Written comments must be received by [TBD]. All comments received during the comment period will be considered by the District and addressed as necessary in any Final Determination of Compliance.

The power plant approval process also provides opportunities for members of the public to participate in person in public hearings regarding this project. The District may hold a public meeting in accordance with Regulation 2, Rule 2, Section 405 to receive verbal comment from the public if there is sufficient reason to do so. Members of the public who would like to request that the District hold a public meeting should make such a request, in writing, to Mr. Patil at the address set forth in the preceding paragraph prior to the end of the comment period, and should explain the reasons why a public meeting is warranted. Members of the public will also be afforded an opportunity to participate in public hearings regarding the project at the Energy Commission as part of the Commission's environmental review process. The public hearings before the Energy Commission will encompass all aspects of the project, including air quality issues and all other environmental issues.

Interested members of the public are invited to learn more about the project as part of the public review and comment process. Detailed information about the project and how it will comply with applicable regulatory requirements are set forth in the subsequent sections of this document. All supporting documentation, including the permit application and data submitted by the applicant and all other information the District has relied on in its analysis, are available for public inspection at the Communication and Outreach Division Office located on the 5th Floor of District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. This Engineering Evaluation and the supporting documentation are also available on the District's website at www.baaqmd.gov/. The public may also contact Mr. Patil for further information (see contact information above). **Para obtener información en español, comuníquese con Brenda Cabral en la sede del Distrito, (415) 749-4686**, bcabral@baaqmd.gov.

In addition to the Air District's permitting process involving air quality issues, interested members of the public are also invited to participate in the Energy Commission's licensing proceeding, which addresses other environmental concerns including those that are not related to air quality. For more information, go to the following CEC website: http://www.energy.ca.gov/sitingcases/mariposa/index.html. The public may also contact the Energy Commission's Public Adviser's office at:

Public Adviser
California Energy Commission
1516 Ninth Street, MS-12
Sacramento, CA 95814
Phone: 916-654-4489
Toll-Free in California: 1-800-822-6228 E-mail: PublicAdviser@energy.state.ca.us

3. Project Description

The Mariposa Energy Project is a proposed nominal 200-megawatt “peaker” power plant to be located near Byron, CA. The facility would consist of four GE LM6000 PC Sprint natural gas fired simple-cycle combustion turbines with a nominal electrical output of 50 MW per turbine. This section describes the proposed project’s function as a simple-cycle “peaker” power plant, describes where it would be located and how it would be operated, and provides details about project ownership and the specific equipment being proposed for the project.

3.1 The Mariposa Energy Project: A Simple-Cycle “Peaker” Power Plant

The proposed Mariposa Energy Project would be a “peaker” plant, meaning that it is designed to provide electricity to the grid at times of peak demand. Peaking power plants are power plants that generally only run during periods of high demand for electricity, most often during the summertime when air conditioning use is highest and typically in the late afternoon when people are returning from work and many businesses remain open. The proposed power plant would operate up to 46% of the year depending on the demand for electricity in the region. PG&E would be responsible for dispatching the plant to meet electrical demand through a power purchase agreement between PG&E and Mariposa.

The proposed project uses a “simple-cycle” design, meaning that it uses natural gas combustion turbines only, without additional generating equipment, to make electricity. This design is different than a “combined-cycle” design, in which waste heat in the turbine exhaust is used to create steam in a heat-recovery steam generator, which powers a steam turbine to generate additional electricity. The simple-cycle power plant design is especially well suited for peaking power plants because the turbines can be started up very quickly when demand requires it. With combined-cycle power plants, startups take longer because the heat recovery boilers and steam turbine take additional time to come up to operating temperature. Simple-cycle turbines are also well suited to peaking applications because peakers, by their nature, are not called upon to run for extended periods of time. This is an important consideration because peaking power plants are inherently less efficient than combined-cycle power plants, which recover some of the heat from the turbine exhaust that would otherwise be exhausted to the atmosphere. Since peaker plants are operated for a relatively small number of hours per year, this energy penalty – which translates into additional fuel used to generate the same amount of power – is not as much of a concern. Peaking power plants also provide a valuable service to electrical grid operators by providing voltage support and reliability services.

As a peaker plant, the facility will also help to ensure a reliable supply of power as California transitions to a greater supply of renewable power sources such as solar and wind power. As a peaker plant, the project will help provide on-demand standby power capacity for grid stability. The simple-cycle turbines have a very short startup time and can come on-line very quickly to fill in during times when solar energy sources or wind power are not available. As the California Energy Commission has recognized, “some efficient, dispatchable, natural-gas-fired generation will be necessary to integrate renewables into California’s electricity system and meet the state’s

[Renewable Portfolio Standard] and [Greenhouse Gas] goals."[1] Peaker plants fired by clean-burning natural gas are well suited to filling this need.

3.2 Project Location

The proposed Mariposa Energy Project would be located in an unincorporated area of northeastern Alameda County. The site would be located on non-irrigated grazing land southeast of the intersection of Bruns Road and Kelso Road on a 10-acre portion of a 158-acre parcel known as the Lee Property. The site is immediately south of the PG&E Bethany Compressor Station and 230-kilovolt (kV) Kelso Substation. The site is also located approximately 2.5 miles west of the community of Mountain House, 7 miles northwest of Tracy, 7 miles east of Livermore, and 6 miles south of Byron. Figure 1 shows the location of the project within Alameda County. Figure 2 shows the site location. An aerial view of the project site and a plot plan of the proposed Mariposa Energy Project are also provided in Figures 3 and 4, respectively.

[1] California Energy Commission, *Final Commission Decision, Avenal Energy, Application for Certification* (08-AFC-01), Kings County (Dec. 16, 2009) p. 112, Finding of Fact no. 23 (available at: www.energy.ca.gov/2009publications/CEC-800-2009-006/CEC-800-2009-006-CMF.PDF).

Insert: Figure 1 (Figure 1.1-2 (AFC))

Insert: Figure 2 (Figure 1.1-3 (AFC))

Insert: Figure 3 (Figure 1.1-1 (AFC))

Insert: Figure 4 (Figure 2.3-1 (AFC))

3.3 How the Project Will Operate

The proposed facility will generate electric power for the grid using the GE LM6000 simple-cycle combustion turbines. The combustion turbines will generate power by burning natural gas exclusively, which expands as it burns and turns the turbine blades which in turn rotate an electrical generator to generate electricity. As a peaking power plant, MEP will operate during times of very high electrical load, during periods when intermittent renewable source generation experiences fluctuation, when baseload plants are not operating or being brought on-line, or during emergency conditions. The facility will be licensed and permitted to operate up to 4,000 hours per year (46 percent of the year) plus 300 startup and shutdown cycles. However, as a peaking power plant, the actual capacity is expected to be less based on a study conducted by the California Energy Commission.[2]

The GE LM6000 aero-derivative combustion turbine is a two-shaft/two-spool engine consisting of a high pressure and low pressure compressor, a combustor, and a high pressure and low pressure power turbine. The compressors compress the combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the power turbine where the gases expand across the turbine blades, rotating a shaft to power the electric generator. The engine is connected to an air cooled generator operating at 13.8 kV and 60 hertz (Hz). Figure 5 illustrates the gas turbine arrangement and the general layout of a simple-cycle aero-derivative gas turbine power plant such as the proposed Mariposa Energy Project.

The Mariposa Energy Project also includes three features designed to enhance the generating efficiency of the combustion power turbine and reduce the overall air emissions. The first feature is the injection of water into the combustor of a gas turbine to quench the flame and absorb heat, reducing the combustion temperature. This temperature reduction results in a reduction in the formation of thermal NOx. The second feature is the GE SPRINT (Spray Inter-cooled Turbine) technology option. The GE SPRINT technology reduces the air discharge compressor temperature by injecting atomized water into the low- and high-pressure compressors. The SPRINT power augmentation feature results in an increased generating output of approximately 15 percent at ISO conditions for the same quantity of natural gas burned. The third feature includes the use of air-cooled inlet air chiller packages. The combustion turbines operate most efficiently when the inlet air temperature is maintained at a nominal temperature (46°F). Therefore, an inlet air chiller package will be used to cool the turbine's inlet air on days with warmer ambient air temperatures. This feature will provide the maximum benefit when the Mariposa Energy Project is dispatched to meet peak energy demands which typically occur during the summer months.

After exiting the combustion turbines, the hot exhaust gases are then sent through the post-combustion emission controls prior to being exhausted at the stack. The proposed post-combustion emission controls consist of a Selective Catalytic Reduction (SCR) unit to reduce oxides of nitrogen (NOx) in the exhaust and an oxidation catalyst to reduce organic compounds and carbon monoxide (CO) in the exhaust. The emissions of NOx and CO will be monitored by a continuous emissions monitoring system (CEMS) before exiting the stack.

[2] California Energy Commission (CEC), 2006. Errata to the Presiding Member's Proposed Decision, Application for Certification for the Pastoria Energy Facility 160 MW Expansion (05-AFC-1). November 15. http://www.energy.ca.gov/sitingcases/pastoria2/documents/2006-11-15_COMMITTEE_ERRATA.PDF

SCR injects ammonia into the exhaust stream, which reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream as what is commonly called “ammonia slip”. An oxidation catalyst oxidizes the carbon monoxide and unburned hydrocarbons in the exhaust gases to form CO_2.

The project has been designed to use an air-cooled condenser to reject the heat from the turbine inlet air cooling process. Therefore, the project will not require the use of a cooling tower or wet surface air cooler, which eliminates the potential for particulate emissions associated with evaporative cooling tower drift.

The fire protection system will be designed to protect personnel and limit property loss and plant downtime in the event of a fire. The fire water supply and pumping system will provide fire-fighting water using a backup diesel fire pump driver rated at 220 horsepower or less. The diesel fire pump operation will be limited to 4 hours per year for maintenance and testing activities.

3.4 Project Ownership

The Mariposa Energy Project would be owned by Mariposa Energy LLC (Applicant), a subsidiary of Diamond Generating Corporation, a wholly owned subsidiary of Mitsubishi Corporation.

3.5 Equipment Specifications

The equipment that Mariposa Energy LLC has identified for use at the Mariposa Energy Project consists of the following:

S-1 Combustion Turbine Generator #1, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-1 Oxidation Catalyst, and A-2 Selective Catalytic Reduction System (SCR).

S-2 Combustion Turbine Generator #2, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-3 Oxidation Catalyst, and A-4 Selective Catalytic Reduction System (SCR).

S-3 Combustion Turbine Generator #3, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-5 Oxidation Catalyst, and A-6 Selective Catalytic Reduction System (SCR).

S-4 Combustion Turbine Generator #4, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-7 Oxidation Catalyst, and A-8 Selective Catalytic Reduction System (SCR).

S-5 Fire Water Pump Diesel Engine, Cummins 220 brake horsepower, Model CFP7E-F40 or equivalent Tier III compliant engine.

Insert: Figure 5

4. Facility Emissions

This section describes the air pollutant emissions that the Mariposa Energy Project will have the potential to emit, as well as the principal regulatory requirements to which the emissions will be subject. Detailed emission calculations, including the derivations of emission factors, are presented in the appendices.

4.1 Criteria Pollutants

4.1.1 Hourly Emissions from Gas Turbines

The Mariposa Energy Project's generating equipment – the simple-cycle gas turbines – will have the potential to emit up to the following amounts of regulated air pollutants per hour, as set forth in **Table 1**. These are the maximum emission rates for regulated air pollutants from the project during normal steady-state operations, and will be limited by enforceable permit conditions. (See Appendix [TBD] for detailed emission calculations.)

TABLE 1. STEADY-STATE EMISSIONS RATES

Pollutant	One Simple-Cycle Turbine Emissions Rate (lb/hr)
NO_x (as NO_2)	4.40
CO	2.14
POC (as CH_4)	1.22
$PM_{10}/PM_{2.5}$	2.50
SO_x (as SO_2) Maximum[a]	1.35
SO_x (as SO_2) Average[b]	0.34

[a] Maximum SO_x emissions based on 1 grain sulfur per 100 scf of natural gas.
[b] Average SO_x emissions based on 0.25 grains sulfur per 100 scf of natural gas.

Note that particulate matter from natural gas combustion sources normally has a diameter less than one micron.[3] Therefore, the particulate matter will be both PM_{10} (particulate matter with a diameter of less than 10 microns) and $PM_{2.5}$ (particulate matter with a diameter of less than 2.5 microns). $PM_{2.5}$ is a subset of particulate matter that has recently come under heightened regulatory scrutiny, and the District is in the process of developing regulations specifically directed to controlling $PM_{2.5}$ but are currently not in place yet. However, for this facility, the District's existing PM_{10} regulations will be equally effective in controlling $PM_{2.5}$ because all of the PM emissions from this facility will be both $PM_{2.5}$ and PM_{10}.

[3] See AP-42, Table 1.4-2, footnote c, 7/98 (available at www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf).

4.1.2 Emissions During Gas Turbine Startup, Shutdown, and Fire Pump Testing Operations

Maximum emissions during turbine startups and shutdowns, when the turbines are operated when emissions control equipment may not be fully operational, are summarized in **Table 2**. (These operating scenarios are discussed in more detail in Sections 5.7, below.) Table 2 shows the startup emissions limits for each turbine.

TABLE 2: GAS TURBINE EMISSIONS DURING STARTUP SHUTDOWN OPERATIONS

Pollutant	Simple-Cycle Startup Emissions Rates (lb/event)a	Single Simple-Cycle Startup (lb/hour)	Simple-Cycle Shutdown Emissions Rate (lb/event)b	Single Simple-Cycle Shutdown (lb/hour)	Simple-Cycle Startup/Shutdown Emissions Rates (lb/hour)c
NO_x (as NO_2)	14.2	16.4	3.2	6.5	18.5
CO	14.1	15.2	2.7	4.3	17.3
POC (as CH_4)	1.1	1.7	0.19	1.1	1.6
$PM_{10}/PM_{2.5}$	1.1	2.2	0.55	2.2	2.2
SO_x (as SO_2)	0.68	1.4	0.34	1.4	1.4

[a] Startups not to exceed 30 minutes.
[b] Shutdowns not to exceed 15 minutes.
[c] Worst case hourly emissions assume one startup and one shutdown in one hour.

Maximum emissions for the fire pump are summarized in **Table 3.** The emission estimates are based on a maximum testing period of 20 minutes per hour.

TABLE 3. MAXIMUM HOURLY FIRE PUMP EMISSIONS DURING MAINTENANCE AND TESTING

Pollutant	HOURLY EMISSION RATE (lb/hr)
NOx (as NO_2)	0.37
CO	0.18
POC (as CH_4)	0.0091
$PM_{10}/PM_{2.5}$	0.016
SOx (as SO_2)	0.0008

Note: Emissions based on the Cummins Model CFP7E-F40 Tier 3 emission data spec sheet and 15 ppm sulfur diesel fuel[4].

[4] Cummins Model CFP7E-F40 Tier 3 emission data spec sheet

4.1.3 Daily Facility Emissions

Maximum daily emissions of regulated air pollutants emissions for the Mariposa Energy Project are set forth in **Table 4** below. The table shows emissions both from the gas turbines and the diesel fire pump.

These daily emission rates are used to determine what sources at the facility are subject to the requirement to use "Best Available Control Technology" pursuant to District New Source Review regulation (NSR; Regulation 2, Rule 2). Pursuant to District Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NOx, SO_2, PM10, or CO is subject to the BACT requirement for that pollutant.

TABLE 4. MAXIMUM DAILY REGULATED CRITERIA AIR POLLUTANT EMISSIONS FOR FACILITY.

	Pollutant (lb/day)				
Source	**Nitrogen Oxides (as NO_2)**	**Carbon Monoxide**	**Precursor Organic Compounds**	**Particulate Matter (PM_{10})**	**Sulfur Dioxide**
One Simple-Cycle Unit [a]	274.8	233.6	33.5	60.0	21.8
Four Simple-Cycle Units [a]	1,099.2	934.2	134.1	240.0	87.3
Total including fire pump	1,099.6	934.4	134.1	240.0	87.3

Note: Daily NOx, CO, and VOC emissions were estimated assuming 12 startup events, 12 shutdown events and 15 hours of steady-state operation at full capacity with air inlet chillers operating. Daily SO_2, and $PM_{10/2.5}$ emissions are based on 24 hours of steady-state operation at full capacity with air inlet chillers operating. See Appendices for emissions calculations.

As Table 4 shows, the gas turbines will emit over 10 pounds per highest day of NOx, CO, POC, PM10, and SO_2, and are required to use Best Available Control Technology per Regulation 2-2-301 to limit emissions of these pollutants. The Air District's analysis of the Best Available Control Technology emission limits for this equipment is described in Section 5 below.

The 220 horsepower diesel fired internal combustion engine (ICE) fire pump driver will be subject to the emission limitation requirements outlined in the California Air Toxic Control Measure (ATCM). The certified emissions for the proposed engine will meet the emission requirements specified in the ATCM. Furthermore, based on the proposed operating limitation, the ICE will not be operated for more than 4 hours for maintenance and testing annually. Therefore, the ICE will not emit over 10 pounds per day of any pollutant and is not subject to further BACT analysis.

4.1.4 Annual Facility Emissions

The maximum annual emissions of regulated air pollutants for the proposed Mariposa Energy Project are set forth in **Table 5** below. Table 5 shows the annual emissions from the facility, both from the gas turbines and the diesel fire pump. These emissions reflect the 46 percent annual capacity factor proposed by the applicant plus the startup and shutdown emissions. Annual facility emissions are used to determine whether the facility will need to offset its emissions with

Emissions Reduction Credits under District Regulations 2-2-202 and 2-2-203. Offsets are required for NOx and POC emissions over 10 tons per year, and for PM10 and SO_2 emissions over 100 tons per year.

TABLE 5. MAXIMUM ANNUAL CRITERIA AIR POLLUTANT EMISSIONS FOR THE FACILITY.

	NO_2 (ton/yr)	CO (ton/yr)	POC (ton/yr)	PM_{10} (ton/yr)	SO_2 (ton/yr)
One Simple-Cycle Gas Turbine	11.4	6.8	2.6	5.3	0.8
All Four Simple-Cycle Gas Turbines	45.6	27.2	10.3	21.1	3.1
Total subject to Air District Regulations	45.6	27.2	10.3	21.1	3.1

Notes: See Appendices for Emission Calculations.

These annual emissions rates show that the facility will be required to offset its emissions of NOx and POC under District Regulation 2-2-302, because emissions will be over 10 tons per year (and for NOx will have to provide credits at a ratio of 1.15 tons of credits per 1 ton of emissions, because emissions will be over 35 tons per year). The facility will not be required to offset its PM10 and SO_2 emissions under District Regulation 2-2-303 because emissions will be less than 100 tons per year.

4.2 Toxic Air Contaminants

Toxic Air Contaminants (TACs) are a subset of air pollutants that can be harmful to health and the environment even in very small amounts. **Table 6** provides a summary of the maximum annual facility toxic air contaminant (TAC) emissions from the project.

Table 6 is also a summary of the emissions used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 5 ppmvd @ 15% O_2 from the gas turbine SCR systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Regulation 2, Rule 5.

TABLE 6. MAXIMUM FACILITY TOXIC AIR CONTAMINANT (TAC) EMISSIONS

Toxic Air Contaminant	Project lb/hour	Project lb/year	Acute Risk Screening Trigger Level (lb/hr)	Chronic Risk Screening Trigger Level (lb/yr)
1,3-Butadiene	0.0011	1.04	--	0.63
Acetaldehyde	0.26	1112	1.0	38
Acrolein	0.036	153	0.0055	14
Ammonia	13.1	56400	7.1	7700
Arsenic	0.0000060	0.000072	0.00044	0.0072
Benzene	0.026	108	2.9	3.8
Cadmium	0.0000057	0.000068	--	0.026
Chloro-benzene	0.00000075	0.0000090	--	3900
Copper	0.000015	0.00019	0.22	--
Cr(VI)	0.00000038	0.0000045	--	0.00077
Diesel Exhaust PM	0.016	0.20	--	0.34
Ethyl Benzene	0.034	145	--	43
Formaldehyde	1.74	7440	0.12	18
HCl	0.00070	0.0084	4.6	3500
Hexane	0.49	2104	--	270000
Lead	0.000031	0.00038	--	3.2
Manganese	0.000012	0.00014	--	3.5
Mercury	0.0000075	0.000090	0.0013	0.27
Naphthalene	0.0032	13.5	--	3.2
Nickel	0.000015	0.00018	0.013	0.43
PAHs	0.00016	0.12	--	0.0069
Propylene	1.46	6240	--	120000
Propylene Oxide	0.090	388	6.8	29
Selenium	0.0000083	0.00010	--	770
Toluene	0.13	576	82	12000
Xylene	0.049	212	49	27000
Zinc	0.000084	0.0010	--	--

Note: Emissions from the 220 hp diesel fire pump driver are included.

If emissions are above certain established screening levels prescribed in Table 2-5-1 of Regulation 2, Rule 2, a health risk assessment is required. Where no acute trigger level is listed for a TAC, none has been established for that TAC. Based on the information contained in Table 6, a health risk assessment is required by District Regulation 2, Rule 5. The health risk assessment is conducted to determine the potential impact on public health resulting from the worst-case TAC emissions from the project.

The results of the health risk assessment are discussed in full in Section 8 of this document. Briefly, the health risk assessment found a maximum increased cancer risk of [TBD by BAAQMD] in one million for the maximally exposed individual near the facility. Under District Regulation 2-5, these carcinogenic risk levels are less than significant because they are less than 1.0 in one million. The highest chronic non-cancer hazard index for the project is [TBD by BAAQMD] and the highest acute non-cancer hazard index for the project is [TBD by BAAQMD]. These non-cancer risks are less than significant under District Regulation 2-5 because they are less than 1.0.

5. Best Available Control Technology (BACT)

The District's New Source Review regulations require the proposed Mariposa Energy Project (MEP) to utilize the "Best Available Control Technology" (BACT) to minimize air emissions, as discussed in more detail below. The MEP simple-cycle turbines are subject to BACT under the District's New Source Review regulations (Regulation 2, Rule 2, Section 301) for NOx, CO, POC, PM10, and SOx because each unit will have the potential to emit more than 10 pounds per highest day of those pollutants. This section describes how the BACT requirements will apply to the facility.

5.1 Introduction

District Regulation 2-2-301 requires that MEP use BACT to control NOx, CO, POC, PM10, and SOx emissions from sources that will have the potential to emit over 10 pounds per highest day of each of those pollutants. Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

1. "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or
2. The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or
3. Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or
4. The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

For ease in reviewing BACT assessments, the above definition of BACT can be broken down to two general BACT categories: 1) "technologically feasible and cost-effective" (referred to as BACT 1) and 2) "achieved in practice" (referred to as BACT 2).[5] The first category is a more stringent level of BACT control and is technology forcing; it generally refers to advanced control devices or techniques. The control equipment or technology must be commercially available, and demonstrated effective and reliable on a full scale unit and shown to be cost-effective on a dollars per ton of pollutant removed basis. The actual cost analysis methodology will be discussed later in this section. Note that the District BACT definition, developed under CARB guidelines, does not explicitly require that the control be demonstrated for any specific length of time. However, in reviewing BACT performance data, District staff must make the engineering determination that the control would reasonably be expected to perform for a sufficient duration to make the control option cost-effective. Often, control techniques under the technologically feasible and cost-effective category are technology transfers from successful applications on similar types of

[5] Bay Area Air Quality Management District (BAAQMD) Best Available Control Technology (BACT) Workbook Policy and Implementation Procedure, Interpretation of BACT - http://hank.baaqmd.gov/pmt/bactworkbook/default.htm

equipment or emission streams. In that case, the control has been "achieved in practice" (i.e., BACT 2) on a similar source or equipment category, but has not been used for the particular source or equipment in question. A feasibility and cost-effectiveness analysis would then be necessary. In general, cost effectiveness analysis is done on a source by source basis. The Bay Area Air Quality Management District's guideline cost limits are as follows[6]:

Pollutant Maximum Cost ($/ton)
POC = 17,500
NOx = 17,500
SO_2 = 18,300
CO n/d
PM10 = 5,300
NPOC = 17,500

Note that the BAAQMD has not included a cost effectiveness value for CO, but has used CO cost effectiveness values from the South Coast Air Quality Management District of $400 per ton average and $1,150 per ton incremental in the recent Marsh Landing Generating Station Preliminary Determination of Compliance[7].

The BACT 2 category, "achieved in practice" applies to the most effective emission control device already in use or the most stringent emission limit achieved in the field for the type and capacity of equipment comprising the source under review and operating under similar conditions, i.e., process throughput and material usage, hours of operation, site-specific limitations or opportunities, etc. For example, the control device performance or emission limit has already been verified by source tests or other appropriate documentation approved by this District or another California air district.

The following sections provide the basis for the District BACT analyses for this equipment.

5.2 Gas Turbine Selection

Mariposa Energy LLC's (Mariposa Energy) participation in PG&E's RFO process resulted in the signing of a Power Purchase Agreement (PPA) between PG&E and Mariposa Energy. Therefore, the gas turbine selection process for MEP was predicated on the contractual terms of the PPA between PG&E and Mariposa Energy. The PPA contractual terms require the generation of 184 MW (at a peak July temperature of 93°F and 26 percent relative humidity) into the PG&E electrical system, a high degree of unit turndown with the minimum generation rate of 24.9 MW, and up to 300 "on-demand" system starts and 4,000 hours of peaking operation per turbine per year[8].

[6] BAAQMD BACT Workbook Policy and Implementation Procedure, Interpretation of BACT.
[7] BAAQMD. "Preliminary Determination of Compliance for the Marsh Landing Generating Station". March, 2010. http://www.energy.ca.gov/sitingcases/marshlanding/documents/other/2010-03-24_Bay_Area_AQMD_PDOC.pdf
[8] Mariposa Energy to BAAQMD, January 27, 2010. Letter titled "Mariposa Energy Project – Application No. 20737 Plant No. 19730 Reductions in the Number of Hours Required for Commissioning, the Startup and Shutdown Emission Rates, and the CO and PM10/2.5 Combustion Turbine Emission Rates"

There are two types of gas turbines commonly used in the power generation industry. These are the large heavy-duty industrial ("frame") design and the aero-derivative design derived from aircraft engines. Both gas turbines have been widely used and the selection of the turbine in a given application is determined by the amount of capacity required and the anticipated cycling duty and load profile.

Large Industrial Turbines. An industrial frame gas turbine consists of an axial flow compressor with multiple can-annular combustors, each connected by cross flame tubes. The gas turbine has a firing temperature of around 2,500°F. It is anticipated that future design advancements will allow industrial frame turbines to reach firing temperatures around 3,000°F to achieve higher efficiencies. The advantages of the large frame industrial gas turbines are their long life, reliable operation, and lower combustion emissions. Since the 1990s, the industrial frame gas turbines have been the primary machine used in combined cycle power plants.

Large industrial frame gas turbines are able to use a can-annular configuration because the combustion chamber is large enough to use a multiple combustion nozzle approach in a confined space known in the industry as a "basket." These multiple baskets are placed in a circumferential configuration in the center of the gas turbine and can be controlled independently to improve the combustion process. In many cases, a ring of nozzles is placed in the "basket" concentrating the process in a primary zone for combustion. A can-annular configuration requires increased cooling of circulating air around the baskets and results in a lower achievable firing temperature. However, the lower firing temperature also lowers efficiency of the large industrial frame turbine when compared to the aero-derivative gas turbine technology.

Mariposa Energy considered the use of heavy-duty (i.e., industrial) turbines for MEP. However, industrial gas turbines with electrical-generation capacities in the 45 to 47 MW range, such as the Siemens SGT-800 units, typically have lower thermal efficiencies at all operating conditions compared to a comparable aero-derivative turbine, such as the GE LM6000. For instance, performance specifications received from Siemens for the SGT-800 indicate the unit has a heat rate (a measure of efficiency) of 9,231 British Thermal Units (Btu) per kilowatt-hour (Btu/kWh LHV at 42°F), whereas, the LM6000 combustion turbine proposed by Mariposa Energy has a heat rate of 8,548 Btu/kWh (LHV at 46°F – see **Table 7** below). This represents an 8% decrease in energy efficiency compared to the LM6000 unit. Furthermore, the reduction in efficiency between the SGT-800 and LM6000 units is more dramatic at lower operating loads. For instance, at 50% load, the SGT-800 unit has a heat rate of 11,702 Btu/kWh and the LM6000 has a heat rate of 10,204 Btu/kWh.[9],[10] Therefore, Mariposa Energy would not be able to meet the specific MEP unit efficiency/heat rate requirements in the PPA using the industrial frame technology. Furthermore, the lower efficiency of the industrial frame technology would also result in an increase in emissions of greenhouse gases over the LM6000 units selected for the project.

Aero-derivative Gas Turbines. Aero-derivative gas turbines are also known as aircraft-derivative gas turbines. Aero-derivative gas turbines consist of two basic components: an aircraft-derivative gas generator and a free power generator. The gas generator serves as a producer of gas energy or gas horsepower where the high pressure turbine section extracts enough energy to drive the high pressure compressor section connected to the same shaft. Hot gases pass to the low pressure turbine

[9] Siemens Performance & Technical Information SGT-800, X2103364E, page 2.
[10] Mariposa Energy to BAAQMD, January 27, 2010 Attachment 2, pages 1-2.

section that in turn drives the low pressure compressor section on a separate but concentric shaft inside the shaft connecting the high pressure compressor and turbine sections. The concentric shafts are able to operate at independent speeds thus optimizing the efficiency of the turbine. In an aircraft engine application, the low pressure turbine exhaust would be available to provide forward propulsion thrust. In a stationary application for power generation the energy in the exhaust gases is captured by a power turbine and used to drive an electrical generator.

Aero-derivative gas turbines are generally smaller in size and power output than the industrial frame turbines. These turbines are used in both combined cycle and simple cycle mode and have favorable maintenance considerations due to modular design features developed for aircraft engine applications. The aero-derivative gas turbine is designed to withstand many stops and starts and is very adaptable to frequent load changes making it an ideal choice for load-following plant applications that demand the highest level of operating flexibility.

In contrast to the industrial gas turbine, the aero-derivative gas turbine consists of an annular combustor. The annular combustors are used mainly in aero-derivative gas turbines because the use of concentric rotating shafts and a low and high pressure turbine section requires the ignition to be in the frontal position. This design uses individual multiple fuel nozzles providing combustion and is usually a straight through flow type with the outside casing radius the same size as the compressor casing, resulting in a more streamlined design. The annular combustor requires less cooling air compared to the can-annular design, which supports a higher firing temperature resulting in better efficiency. The higher fire temperature is an advantage, but leads to higher NOx formation.

The GE LM6000 turbine is a common aero-derivative turbine chosen for highly flexible, dispatchable, and quick start facilities in California, with an operating range from approximately 25 to 50 MW at 50 percent load and full load, respectively. Mariposa Energy considered three LM6000 models available at the time of the release of the RFO (April 2008). The three LM6000 models included the LM6000PC (water injected), the LM6000PD (dry low-NOx or DLE), and the LM6000PF (Ultra-DLE). The LM6000 turbines also have a SPRINT (Spray Inter-cooled Turbine) technology option. The GE SPRINT technology is GE patented technology that reduces compressor discharge temperature by injecting atomized water into the low- and high-pressure compressors. According to GE product materials, the SPRINT power augmentation feature results in an increased generating output of approximately 15 percent and 11 percent at ISO conditions for the water injected and DLE models, respectively[11]. For instance, the GE LM6000PC and LM6000PD turbines have a full load electrical capacity of approximately 49.7 and 46.9 MW at ISO conditions (59 °F). Therefore, the maximum output for the LM6000PC and LM6000PD turbines is increased to approximately 50 and 47 MW, respectively, with the inclusion of the SPRINT power augmentation.

As part of the turbine selection process, the turbine vendor provided performance data for both the water-injected and DLE LM6000 SPRINT gas turbines[12] (see Table 7). As presented in Table 7, the water injected LM6000 gas turbine (i.e., LM6000PC) results in a higher electrical production rate compared to the DLE models. For example, the electrical output for the LM6000PC model is approximately 2.6 MW more than the DLE models at 93°F or approximately 10.4 MW for the

[11] GE. "LM6000 SPRINT Gas Turbine Generator Set" Product Information. March 2003.
[12] GE Performance Data for LM6000 PC, PD, and PF SPRINT Gas Turbines.

project. Although the LM6000PF turbine has a lower NOx emission rate than the PC or PD models, the DLE models have higher hydrocarbon and CO emission rates (except at the 17°F temperature case) compared to the water injected PC turbine. Furthermore, the use of selective catalytic reduction (SCR) effectively reduces the NOx emission rate for all three turbines to 2.5 ppm (see discussion on the feasible NOx control technologies). Therefore, the lower LM6000PF NOx emission rate does not counter the overall benefit of an additional 10.4 MW of electric generation produced by the LM6000PC turbine under the same ambient conditions.

Because of the reliability requirements of the PPA, Mariposa Energy also researched the reliability of each LM6000 model. According to GE, more than 600 LM6000 power generation packages collectively have been sold worldwide, which have accumulated more than ten million operating hours at 98.8 percent documented gas turbine availability and 97.7 percent gas turbine and generator set availability.[13] Of the approximately 600 LM6000 packages sold, approximately 500 have been the LM6000PC (i.e., water injected) turbine and approximately 100 have been the LM6000 PD turbine. At the time of the RFO, fewer than five LM6000 PF turbines had been sold worldwide. Therefore, the LM6000PF turbine were determined to be less desirable than the LM6000PC and LM6000PF turbines for meeting the "on demand" and reliability requirements of the RFO.

Overall, all three of the LM6000-based gas turbines could meet the project contractual requirements of dispatchable and high degree of unit turndown. However, the LM6000PD and LM6000PF gas turbines do not meet the project objective of being capable of generating 184 MW (net electrical output of all 4 combustion turbines including parasitic loads) during peak July conditions. Furthermore, the limited hours of operating data available for the LM6000PF turbine increases the risk the turbine may not be available "on demand" which would lead to the imposition of penalties per the PPA. Therefore, the LM6000PC turbine was selected by Mariposa Energy for MEP in order to meet the electrical output and reliability requirements outlined in the Mariposa Energy PPA with PG&E.

[13] GE," LM6000 Aeroderivative Gas Turbines" Product Information. http://www.gepower.com/prod_serv/products/aero_turbines/en/lm6000.htm. Website Accessed January 2010.

TABLE 7
COMPARISON OF GE LM6000 SPRINT WATER-INJECTED AND DLE COMBUSTION TECHNOLOGIES

Combustion Technology	PC	PD	PF	PC	PD	PF	PC	PD	PF	PC	PD	PF
Ambient Temperature, °F	**17.0**	**17.0**	**17**	**46**	**46**	**46**	**59**	**59**	**59**	**93**	**93**	**93**
Inlet Conditioning	HEAT	HEAT	HEAT	NONE	NONE	NONE	EVAP	EVAP	EVAP	EVAP	EVAP	EVAP
Load Rate, Percent	100	100	100	100	100	100	100	100	100	100	100	100
Electrical Production, MW	49.9	48.3	47.9	50.7	47.8	47.7	49.7	46.9	46.8	46.3	43.8	43.7
Heat Rate*, Btu/kW-hr, LHV	8483	8115	8128	8548	8238	8248	8566	8276	8283	8647	8407	8414
NOx Control	Water	DLE	DLE	Water	DLE	DLE	Water	DLE	DLE	Water	DLE	DLE
Emissions Rates												
NOx ppmvd Ref 15% O_2	25	25	15	25	25	15	25	25	15	25	25	15
CO ppmvd Ref 15% O_2	48	25	25	20.9	25	25	15	25	25	7.6	25	25
HC ppmvd Ref 15% O_2	6	15	15	2.2	15	15	2.1	15	15	2.1	15	15

PC = GE LM6000PC SPRINT Turbine
PD = GE LM6000PD SPRINT Turbine
PF = GE LM6000PF SPRINT Turbine
Water = water injected
DLE = dry low NOx
ppmvd Ref 15% O_2 = parts per million by volume dry corrected to 15% oxygen
HC = precursor organic compounds
* estimated

5.3 Best Available Control Technology for Oxides of Nitrogen (NO_x)

Oxides of Nitrogen (NO_x) are a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_x is formed when the heat of combustion causes the nitrogen molecules in the combustion air to dissociate into individual nitrogen atoms, which then combine with oxygen atoms to form nitric oxide (NO) and nitrogen dioxide (NO_2). This reaction primarily forms NO (95% to 98%) and only a small amount of NO_2 (2% to 5%), but the NO eventually oxidizes and converts to NO_2 in the atmosphere. NO_2 is a reddish-brown gas with detectable odor at very low concentrations. NO and NO_2 are generally referred to collectively as "NO_x".[14] NO_x is a precursor to the formation of ground-level ozone, the principal ingredient in smog.

The District has examined technologies that may be effective to control NO_x emissions in two general areas: combustion controls that will minimize the amount of NO_x created during combustion; and post-combustion controls that can remove NO_x from the exhaust stream after combustion has occurred.

Cost Effective and Feasible (BACT 1) NO_x Control Technologies for Simple-Cycle Gas Turbines

Combustion Controls

The formation of NOx during combustion is highly dependent on the primary combustion zone temperature, as the formation of NOx increases exponentially with temperature. Therefore, there are three basic strategies to reduce thermal NOx in the combustion process:

- Reduce the peak combustion temperature
- Reduce the amount of time the air/fuel mixture spends exposed to the high combustion temperature
- Reduce the oxygen level in the primary combustion zone

It should be noted, however, that techniques that control NOx by reducing combustion temperatures may involve a trade-off with the formation of other pollutants. Reducing combustion temperatures to limit NOx formation can decrease combustion efficiency, resulting in increased byproducts of incomplete combustion such as carbon monoxide and unburned hydrocarbons. Unburned hydrocarbons from natural gas combustion consist of methane, ethane and precursor organic compounds. The District prioritizes NOx reductions over carbon monoxide and POC emissions because the Bay Area is not in compliance with applicable ozone standards, but does

[14] NO_x can also be formed when a nitrogen-bound hydrocarbon fuel is combusted, resulting in the release of nitrogen atoms from the fuel (fuel NO_x) and NO_x can be formed by organic free radicals and nitrogen in the earliest stages of combustion (prompt NO_x). Natural gas does not contain significant amounts of fuel-bound nitrogen, therefore thermal NO_x is the primary formation mechanism for natural gas fired gas turbines. References to NO_x formation during combustion in this analysis refer to "thermal NO_x", NO_x formed from nitrogen in the combustion air.

comply with the carbon monoxide standards. Therefore, the District requires applicants to minimize NOx emissions to the greatest extent feasible, and then optimize CO and POC emissions for that level of NOx control. This is a trade-off that must be kept in mind when selecting appropriate emissions control technologies for these pollutants.

The District has identified the following available combustion control technologies for reducing NOx emissions from the combustion turbines.

Steam/Water Injection: Steam or water injection was one of the first NOx control techniques utilized on gas turbines. Water or steam is injected into the combustion zone to act as a heat sink, lowering the peak flame temperature and thus lowering the quantity of thermal NOx formed. The injected water or steam then exits the turbine as part of the exhaust. The lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion, however, and so carbon monoxide and POC emissions can increase as water/steam-to-fuel ratios increase. In addition, the injected steam or water may cause flame instability and can cause the flame to quench (go out). Water/steam injection in the combustion turbines used in conjunction with Low-NOx burners can achieve NOx emissions as low as 25 ppm @ 15% O_2.[15]

Dry Low-NOx Combustors: Another technology that can control NOx without water/steam injection is Dry Low-NOx combustion technology. Dry Low-NOx Combustors reduce the formation of thermal NOx through (1) “lean combustion” that uses excess air to reduce the primary combustion temperature; (2) reduced combustor residence time to limit exposure in a high temperature environment; (3) “lean premixed combustion” that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen and then a secondary lean burn-stage to complete combustion in a cooler environment. Dry Low-NOx combustors can achieve NOx emissions as low as 15 ppm for aero-derivative gas turbines.[16]

Catalytic Combustors: Catalytic combustors, marketed under trade names such as XONONTM, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NOx formation. XONONTM uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. Although, the technology has been successfully demonstrated in a 1.5 megawatt simple-cycle pilot facility and is commercially available for turbines rated up to 10 megawatts, catalytic combustors such as XONONTM have not been demonstrated on large-scale utility gas turbines. Therefore, XONONTM is not currently available for turbines of the size proposed for MEP.

Post-Combustion Controls

The District has identified the following post-combustion controls that can remove NOx from the emissions stream after it has been formed.

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[15] M. Schorr, J. Chalfin, GE Power Systems, “Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?”, 9/99, pg. 2
[16] GE Performance Data for LM6000 PC, PD, and PF SPRINT Gas Turbines.

Selective Catalytic Reduction (SCR): Selective catalytic reduction injects ammonia into the exhaust stream, which reacts with the NOx and oxygen in the presence of a catalyst to form nitrogen and water. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask or poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream as what is commonly called "ammonia slip". The SCR catalyst requires replacement periodically. SCR is a widely used post-combustion NOx control technique on utility-scale gas turbines, usually in conjunction with combustion controls. SCR used in conjunction with water/steam injection in the combustion turbines can achieve NOx emissions as low as 2.5 ppm @ 15% O_2.

Selective non-catalytic reduction (SNCR): Selective non-catalytic reduction 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 1400° to 2100° F[17] and is most commonly used in boilers because combustion turbines do not have exhaust temperatures in that range. Selective non-catalytic reduction (SNCR) requires a temperature window that is higher than the exhaust temperatures from utility combustion turbine installations.

EMx™: EMx™ (formerly SCONOx™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NOx, CO, VOC and optionally SOx emissions for gas turbine applications. A coated catalyst oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, and the NO_2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regenerative gas is periodically passed through the catalyst to desorb the NO_2 from the catalyst and reduce it to elemental nitrogen (N_2). The regeneration gas is created by reacting natural gas with air in the presence of a nickel oxidation catalyst, which is electrically heated to 1,900ºF. This gas is then mixed with steam (produced by a steam generator) and passed over a second catalyst to form the regeneration gas. No ammonia is used by the EMx™ process.

Historically, the EMx™ catalyst requires regular removal and washing of the catalyst with reagents to restore NOx reduction efficiency. Recent advances have been made in the technology to increase resistance to sulfur in the flue gases and performance of the catalyst. EMx™ has been successfully demonstrated on several small combustion turbine projects up to 45 megawatts. However, because MEP is a simple-cycle peaking facility, it would not produce the steam needed for use of the EMx system. Therefore, the project would need to add an auxiliary boiler to generate steam for the EMx technology to function, adding more emissions and counteracting the purpose of the EMx control system. Also, an EMx configuration with an auxiliary boiler has never been demonstrated commercially and is therefore not considered practical or feasible. As a result, this technology would not be feasible with the current project configuration.

In addition to NOx, the District also compared the potential ancillary environmental impacts inherent in SCR and EMx™ to determine whether EMx™ should be considered more "effective" for purposes of the BACT analysis. In particular, the District evaluated the potential impacts from ammonia emissions that would occur from using SCR. The use of SCR will result in ammonia emissions because some of the ammonia used in the reaction to convert NOx to nitrogen and water does not get reacted and remains in the exhaust stream. The excess or unreacted ammonia

[17] NSCR discussion is from Institute of Clean Air Companies website: www.icac.com/i4a/pages/index.cfm?pageID=3399.

emissions are known as "ammonia slip". Ammonia is a toxic chemical that can irritate or burn the skin, eyes, nose, and throat, and it also has the potential for reacting with nitric acid under certain atmospheric conditions to form particulate matter (secondary PM).

With respect to the potential toxic impacts from ammonia slip emissions, the District has conducted a health risk assessment using air dispersion modeling to evaluate the potential health impacts of all toxics emissions from the facility, including ammonia slip. This assessment showed an acute hazard index of [TBD by BAAQMD] and a chronic hazard index of [TBD by BAAQMD]. (See Health Risk Assessment in the Appendices.) A hazard index under 1.0 is considered less than significant. This minimal additional toxic impact of the ammonia slip resulting from the use of SCR is not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The District also considered the potential environmental impact that may result from ammonia transportation and storage associated with the use of SCR. The proposed facility will utilize aqueous ammonia in a 19% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored on-site in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. However, these risks will be addressed in a number of ways under safety regulations and sound industry safety codes and standards. These safety measures include the Risk Management Plan requirement pursuant to the California Accidental Release Prevention Program, which must include an off-site consequences analysis and appropriate mitigation measures; a requirement to implement a Safety Management Plan (SMP) for delivery of ammonia and other liquid hazardous materials; a requirement to instruct vendors delivering hazardous chemicals, including aqueous ammonia, to travel certain routes; a requirement to install ammonia sensors to detect the occurrence of any potential migration of ammonia vapors offsite; a requirement to use an ammonia tank that meets specific standards to reduce the potential for a release event; and a requirement to conduct a "Vulnerability Assessment" to address the potential security risk associated with storage and use of aqueous ammonia onsite. With these safeguards in place, the risks from catastrophic ammonia releases from SCR systems can be mitigated to a less than significant level. The Energy Commission will also be evaluating these risks further through its CEQA-equivalent environmental review process and will impose mitigating conditions as necessary to ensure that the risks are less than significant. For all of these reasons, the potential environmental impact from aqueous ammonia transportation and storage does not justify the elimination of SCR as a control alternative.

Finally, the District also evaluated the potential for ammonia slip to have ancillary impacts on secondary particulate matter. Secondary particulate matter in the Bay Area is mostly ammonium nitrate.[18] The District has historically believed that ammonia was not a significant contributor to secondary particulate matter because the Bay Area is "nitric-acid limited". This means that the formation of ammonium nitrate is constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere. In a nitric acid limited area, emissions of additional ammonia will not contribute to secondary particulate matter formation because not enough nitric acid exists to react with the ammonia.

[18] *See* BAAQMD, Draft Report, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Draft, Oct. 1, 2009), at p. 8 (Draft PM2.5 Modeling Report). The District anticipates issuing a final report in the near future.

The District has recently started reconsidering the extent to which this situation is correct, however. This further evaluation has generally confirmed (preliminarily at least) that the Bay Area is in fact nitric-acid limited, although it has shown that secondary particulate formation mechanisms are highly complex and that the District's historical assumptions that ammonia emissions play no role whatsoever in secondary PM formation may, in hindsight, have been overly simplistic. The focus of the District's further evaluation has been a computer modeling exercise designed to predict what PM2.5 levels will be around the Bay Area, given certain assumptions about emissions of PM2.5 and its precursors, about regional atmospheric chemistry, and about prevailing meteorological conditions. This information was used to create a computer model of regional PM2.5 formation in the Bay Area from which predictions can be drawn about how emissions of PM2.5 precursors will impact regional ambient PM2.5 concentrations. The District's report on its computer modeling exercise has not been finalized, but the draft report concludes that regional ammonium nitrate buildup is limited by nitric acid, not by ammonia.[19] The draft report does find that the amount of available nitric acid is not uniform but varies in different locations around the Bay Area, and consequently the potential for ammonia emissions to impact PM2.5 formation varies around the Bay Area. Specifically, according to the draft report, the model predicts that a reduction of 20 percent in total ammonia emissions throughout the Bay Area would result in changes in ambient PM2.5 levels of between 0 and 4 percent, depending on the availability of nitric acid, leaving open the potential that ammonia restrictions could form a useful part of a regional strategy to reduce PM2.5.[20]. The draft report therefore restates the general conclusion that the Bay Area is nitric-acid limited, although it finds that reductions in the region's ammonia inventory could potentially achieve reductions in PM2.5 concentrations in areas that may have sufficient available nitric acid.[21] The draft report cautions that its assumptions regarding the availability of nitric acid may be misleading, however, because of the preliminary nature of the ammonia emissions inventory used for modeling. Notably, the model also predicts that the East Alameda County area where the facility would be located has low levels of available nitric acid, in the vicinity of 0.25 to 0.50 ppb.[22]

The District does not believe that these indications from its draft PM2.5 data and modeling analysis provide a sufficient basis to disqualify SCR as a BACT technology at MEP based on its potential for ammonia slip emissions. As the report itself notes, the District's work in this area is still at a preliminary stage and it is difficult to draw any firm conclusion about secondary PM formation from it at this time. Moreover, secondary particulate formation is a highly complex atmospheric process, making it especially difficult to estimate how a specific facility's ammonia slip emissions might impact ambient PM levels. The District therefore notes the results of its recent work on secondary particulate matter and will be conducting additional work in this area going forward, but has concluded that there is not enough conclusive evidence at this stage that this facility could have a significant particulate matter impact because of ammonia slip emissions from the SCR system on which to base a BACT determination.

In addition, the District notes that secondary PM formation from ammonia slip is a cold-weather phenomenon that occurs only in the winter. This is because ammonium nitrate volatilizes at higher

[19] Draft PM2.5 Modeling Report at p. E-3 & p. 30.
[20] Draft PM2.5 Modeling Report at pp. E-3 – E-4.
[21] Draft PM2.5 Modeling Report at p. 30.
[22] Draft PM2.5 Modeling Report, Figure 17, p. 31.

temperatures and only exists in a particulate phase in cold weather.[23] Moreover, the Greater Bay Area experiences problems with high ambient PM levels in the air are during the winter months (primarily November through February). The MEP facility will be a peaker plant, however, which operates during periods of peak demand that normally occur during the hot summer months, when air conditioning use is heavy. The District therefore concludes that potential secondary PM formation from ammonia slip would not be a significant concern at MEP because the facility will operate primarily in weather conditions where ammonium nitrate secondary PM cannot form, and at times of the year when PM pollution is less of a concern.

Finally, the Shasta County Air Quality Management District evaluated EMx™ at that facility under a demonstration NOx limit of 2.0 ppm (equivalent to what SCR can achieve for a combined-cycle unit). After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EMx™, and concluded that "Redding Power is not able to reliably and continuously operate while maintaining the NOx demonstration limit of 2.0 ppmvd @ 15% O_2."[24] Although the manufacturer maintains that such problems have been overcome, concerns remain about how consistently the technology would be able to perform.

As noted previously, these concerns would be further compounded by the fact that MEP will be a simple-cycle peaker plant, not a combined-cycle or cogeneration facility like other facilities where EMx™ has been installed. As simple-cycle turbines, the MEP turbines will have an exhaust temperature that is higher than seen at other facilities that the District is aware of currently using EMx™. The proposed MEP turbines will operate at temperatures in the range of 743°F to 863°F, which raises concerns about how easily EMx™ could be applied at MEP. Furthermore, EMx™ requires steam as part of the catalyst regeneration process. Unlike combined-cycle and cogeneration facilities, simple-cycle facilities like MEP do not have any steam production. And there is an additional concern involving the damper systems that would be required with EMx™ to ensure proper regeneration gas distribution. Peaker plants require more rapid startups and more frequent load changes than combined-cycle and cogeneration plants, and to the District's knowledge the effectiveness and longevity of these damper systems has not been demonstrated under these conditions.

Given the uncertainties that still remain in understanding how secondary PM formation is impacted by ammonia slip, the significant additional cost that would be necessary to implement EMx™, and the concern that scaling EMx™ up to fit this facility could involve significant implementation problems, the District has concluded that EMx™ should not be required here as a BACT technology.

<u>Combustion Controls</u>

The Applicant has proposed the use of water injection as BACT for the simple-cycle gas turbines. Water injected combustors are technologically feasible and commonly used at facilities of this type, and combined with post-combustion controls are as effective as the Dry-Low NOx

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23 Draft PM2.5 Modeling Report at p. 10.

24 Letter from R. Bell, Air Quality District Manager, Shasta County Air Quality Management District, to R. Bennett, Safety & Environmental Coordinator, Redding Electric Utility, June 23, 2005.

technology NOx control. Based on the previous discussion, this emissions control technology satisfies the District's BACT requirement.

Post-Combustion Controls

The Applicant has proposed the use of Selective Catalytic Reduction (SCR) in tandem with water injection as BACT for the simple-cycle gas turbines. Selective Catalytic Reduction (SCR) can achieve NOx emissions of 2.5 ppm for simple-cycle turbines. This is the most effective level of control that can be achieved by post combustion controls in conjunction with NOx control in the combustors. Therefore, the District has determined that the use of SCR with water injection meets the BACT requirements for simple-cycle gas turbines.

Achieved in Practice (BACT 2) NO_X Emissions Limit for Simple-Cycle Gas Turbines

To determine the most stringent emissions limit that has been achieve in practice, the District evaluated other simple-cycle natural gas fired turbines. The common simple-cycle gas turbine units proposed for use for intermediate peaking and peaking power in California are the GE LMS-100 gas turbines (100 MW) and the LM6000 gas turbines (49 MW). Numerous projects have been permitted with the LMS-100 gas turbines. The LM6000 gas turbines have been installed at numerous sites across California to provide peaking power.

The District only examined simple-cycle turbines in this review because simple-cycle turbines operate differently than combined-cycle turbines and cannot achieve the same NOx emissions performance as combined-cycle turbines, which are typically capable of meeting a 2.0 ppm limit. Simple-cycle turbines have higher exhaust gas temperatures than combined-cycle turbines because they do not use a heat recovery steam boiler, which removes some of the heat from the exhaust and reduces the exhaust gas temperature. For MEP, the turbine exhaust temperatures from the simple-cycle turbines will exceed 800°F, according to the permit application. These high exhaust temperatures can damage a standard SCR catalyst. As a result, simple-cycle turbines must use less-efficient high-temperature SCR catalysts, or must introduce dilution air to cool the exhaust if they use a standard SCR catalyst. Both of these approaches lead to less efficient SCR performance as compared to a combined-cycle operation. High-temperature catalysts typically have a lower NOx conversion efficiency as compared to conventional SCR catalysts operating at a lower operating temperature. These catalysts have NOx conversion efficiency below 90 percent at elevated temperatures above 800°F,[25] whereas standard catalysts have NOx conversion efficiencies of greater than 90% at 600 to 700°F.[26] Dilution air fans can be used to cool the exhaust prior to entering the SCR system, but this approach has its own drawbacks. The introduction of dilution air may cool the exhaust into the appropriate temperature window, but there may be exhaust hot spots that lower catalyst NOx conversion rates. Optimum SCR performance requires uniform temperature profile, flow profile, and NOx concentration profile across the SCR catalyst face, and introducing large amounts of dilution air disrupts this uniformity. Changing turbine loads also tends to disrupt this uniformity, which makes controlling NOx more difficult with the simple-cycle peaking turbines proposed for the MEP facility. The facility will operate in a load-following mode some of the time and this would result in non-steady-state operation where the exhaust temperature, flowrate, and NOx concentration would all vary as the turbine load is changing.

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[25] BASF, High Temperature SCR for simple-cycle gas turbine applications, 2007.
[26] BASF, NOxCat™ VNX SCR Catalyst for natural gas turbines and stationary engines, 2009.

For all of these reasons, the District has concluded that the NO_x emissions performance that can be achieved with combined-cycle turbines would not be achievable for simple-cycle turbines. Therefore, the District only reviewed the NO_x emissions limits of power plants in a simple-cycle mode abated by SCR systems. The District also reviewed simple cycle BACT determinations listed in the EPA RACT/BACT/LAER and ARB BACT Clearinghouses and also reviewed projects which have recently been evaluated by the CEC. Some of the LMS100 simple-cycle gas turbine permits and LM6000 simple-cycle gas turbine permits with NO_x limits are shown in the **Table 8**.

TABLE 8. NOx EMISSION LIMITS FOR LARGE SIMPLE-CYCLE POWER PLANTS USING SCR

Facility	NOx (ppmvd @ 15% O_2)
Los Esteros Critical Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	5.0 (3-hr)
Panoche Energy Center, SJVAPCD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Walnut Creek Energy Park, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Sun Valley Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
CPV Sentinel Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Lambie Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5 (1-hr)
Riverview Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5 (1-hr)
Wolfskill Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5 (1-hr)
Goosehaven Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5 (1-hr)
San Francisco Electric Reliability Project, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5 (1-hr)
GWF Hanford Combined Cycle Power Plant*, SJVAPCD GE LM6000, 48 MW each	2.5 (1-hr)
GWF Henrietta Combined Cycle Power Plant*, SJVAPCD GE LM6000, 48 MW each	2.5 (1-hr)
Marsh Landing Generating Station, BAAQMD Siemens SGT6-5000F Gas Turbines, 190 MW each	2.5 (1-hr)

*Note: The GWF Hanford and Henrietta Combined Cycle Power Plant projects are currently being operated in simple cycle mode with NOx emission limits of 3.7 ppm and 3.6 ppm, respectively. GWF plans to convert the simple cycle units to combined cycle by adding a once-through boiler which will allow the units to operate in both simple and combined cycle modes. The Hanford and Henrietta conversion projects were approved by the CEC in March 2010. Therefore, the combined cycle projects have not been completed and the LM6000 units have only demonstrated compliance with the 3.7 and 3.6 ppm emission limits.

As shown in Table 8, emissions of 2.5 ppm NOx averaged over one hour is the most stringent emission limitation that has been determined to be achievable at any similar facility using SCR for NOx control (BACT 2). Therefore, the District is also proposing to establish a BACT emissions limit in the permit of 2.5 ppm (averaged over one hour), which is the most stringent limit that has been achieved in practice at any other similar facility (BACT 2) and is the most stringent limit that would be technologically feasible (BACT 1).

<u>NO_x BACT Determinations</u>

The District has determined that 2.5 ppm, averaged over one hour, is the BACT emission limit for NOx for MEP simple-cycle gas turbines. This proposed BACT emissions limit is consistent with the District's BACT Guidelines for this type of equipment. District BACT Guideline 89.1.3 does not specify a technologically feasible and cost-effective control option for NOx for a simple-cycle gas turbine with a rated output > 40 MW (BACT 1). District BACT Guideline 89.1.3 does specify an achieved in practice NOx level of 2.5 ppmvd @ 15% O_2 averaged over one hour, typically achieved through the use of High Temperature Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with steam or water injection (BACT 2). The District is also proposing corresponding hourly, daily and annual mass emissions limits. Compliance with the NOx permit limits will be demonstrated on a continuous basis using a Continuous Emissions Monitor (CEM).

5.4 Best Available Control Technology for Carbon Monoxide (CO)

Carbon monoxide is a colorless odorless gas that is a produced by the partial oxidation of carbon-containing compounds. It is a product of incomplete combustion and forms when there is not enough oxygen to react to produce carbon dioxide.

The District began its BACT analysis by evaluating the most effective control device and/or technique that has been achieved in practice at similar facilities, or is technologically feasible and cost-effective, pursuant to the District's definition of BACT in Regulation 2-2-206. As with NOx, the District has examined both combustion controls to reduce the amount of carbon monoxide generated and post-combustion controls to remove carbon monoxide from the exhaust stream.

<u>Cost Effective and Feasible CO Control Technologies for Simple-Cycle Gas Turbines</u>

<u>Combustion Controls</u>

Carbon monoxide is formed when there is not enough air to fully combust the fuel, and when the air and fuel are not properly mixed due to poor combustor tuning. Maximizing complete combustion by ensuring an adequate air/fuel mixture with good mixing will reduce carbon monoxide emissions by preventing its formation in the first place.

Increasing combustion temperatures can also promote complete combustion, but doing so will increase NOx emissions due to thermal NOx formation as described in the previous section. The District prioritizes NOx control over carbon monoxide control because the Bay Area is not in compliance with the federal standards for ozone, which is formed by NOx emissions reacting with other pollutants in the atmosphere. The District therefore does not favor increasing combustion temperatures to control carbon monoxide. Instead, the District favors approaches that reduce NOx to the lowest achievable rate and then optimize carbon monoxide emissions for that level of NOx emissions.

Good Combustion Practices: The District has identified good combustion practices as an available combustion control technology for minimizing carbon monoxide formation during combustion. Good combustion practices utilize water injection to produce a cooler flame temperature to minimize NOx formation, while still ensuring good air/fuel mixing with excess air to achieve complete combustion, thus minimizing CO emissions.

Post-Combustion Controls

The District has also identified two post-combustion technologies to remove carbon monoxide from the exhaust stream.

Oxidation Catalysts: An oxidation catalyst oxidizes the carbon monoxide in the exhaust gases to form CO_2. Oxidation catalysts are a proven post-combustion control technology widely in use on large gas turbines to abate CO and POC emissions.

EMx™: EMx™, described above in the NO_2 discussion, is a multipollutant control technology that abates CO and POC emissions as well as NOx. EMx™ technology uses a catalyst to oxidize carbon monoxide emissions to form CO_2, and is therefore also an oxidation catalyst. However, it is not a stand-alone oxidation catalyst since the EMx™ is also a NOx reduction device. Hence, it is identified as a device separate from the oxidation catalyst. Although the EMx™ technology has been demonstrated on a 45 MW Alstom GTX 100 combined-cycle gas turbine at the Redding Electric Municipal Plant in Redding, CA, the District is not aware of any EMx™ commercial installations on simple-cycle gas turbines. Furthermore, as described above in the NO_2 discussion, the project would need to add an auxiliary boiler to generate steam for the EMx technology to function, adding more emissions and counteracting the purpose of the EMx control system. Therefore, this technology would not be feasible with the current project configuration.

Oxidation catalysts are capable of maintaining carbon monoxide emission levels at or below 2 ppmvd @ 15% O_2 (1- hour average), depending on load and ambient conditions.[27] However, achieving a CO emission level of 2 ppmvd @ 15% O_2 (1-hour average) requires the use of additional oxidation catalysts which result in an increase in the incremental cost associated with CO emission reductions compared to the current BACT 2 levels of 4 ppmvd @ 15% O_2 (3-hour average) and increases the total back pressure on the units.

Therefore, the District considered whether it would be cost-effective to require the proposed facility to meet an emission limit of 2.0 ppm @ 15% O_2 (1-hour average). As previously discussed, the District has not adopted its own cost-effectiveness guidelines for CO,[28] but a review of other districts in California found no other air districts consider additional CO controls appropriate as BACT where the total (average) cost-effectiveness will be greater than $400 per ton, or where the incremental cost-effectiveness will be over $1,150 per ton.[29] Based on product information

[27] Please see EIT Quote C10-109, Budget CO/VOC Catalyst Matrix, supplied by Mariposa Energy.
[28] BAAQMD BACT Guideline, Policy and Implementation Procedure
[29] *Cf.* South Coast Air Quality Management District, *Best Available Control Technology Guidelines*, August 17, 2000, revised July 14, 2006, pg. 29; available at: www.aqmd.gov/bact

provided by GE, the maximum uncontrolled CO concentration at 15% O_2 would be 48 ppm. Therefore, the District calculated the cost effectiveness of controlling CO from the uncontrolled concentration of 48 ppm to 4 ppm at 15% O_2.[30] The average cost effectiveness for controlling CO emissions from a baseline concentration of 48 ppm (99.9 tons per year) to 4 ppm (8.3 tons per year) would be $3,304 per ton of CO removed.[31] After subsequent discussions, Mariposa Energy proposed a 2 ppm (3-hour) CO emission limit, so the District also determined the cost effectiveness of controlling CO from the uncontrolled concentration of 48 ppm to 2.0 ppm at 15% O_2 over a 3-hour averaging period. The average cost effectiveness for controlling CO emissions from the baseline concentration of 48 ppm (99.9 tons per year) to 2 ppm over a 3-hour averaging period (4.2 tons per year) would be $4,574 per ton of CO removed.

Finally, the District evaluated the incremental cost effectiveness and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently controlling CO emissions from i) 4 ppm to 2 ppm on a 3-hour average basis and ii) 2 ppm on a 3-hour average basis to 2 ppm on a 1-hour average basis. Based on these analyses, the incremental cost effectiveness of achieving a permit limit of 2 ppm CO on a 3-hour basis, above what it would cost to achieve a 4.0 ppm limit on a 3-hour basis, is over $52,300 per ton of additional CO reduction. Moreover, the incremental cost effectiveness of achieving a permit limit of 2 ppm CO on a 1-hour basis, above what it would cost to achieve a 2.0 ppm limit on a 3-hour basis, would be over $44,200 per year, resulting in a total incremental cost of over $42,500 per ton of CO emission reduction.[32] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 2 ppm CO permit limit on a 1-hour basis cannot reasonably be justified as a BACT 1 limit.

Achieved in Practice (BACT 2) CO Emissions Limit for Simple-Cycle Gas Turbines

To establish what level of emissions performance has been achieved in practice for this type of facility, the District reviewed the CO emissions limits of other simple-cycle power plants using oxidation catalyst systems. As with the NOx comparison set forth in Table 8 above, the District reviewed BACT determinations listed in the EPA RACT/BACT/LAER and ARB BACT Clearinghouses and also reviewed projects which have been recently evaluated by the CEC.

The BACT emissions rates presented in **Table 9** are consistent with the District's BACT Guidelines for this type of equipment (simple cycle gas turbine with a rated capacity <40 MWs). The District's Guideline 89.1.3 shows an achieved in practice CO emission concentration of less than 6.0 ppmvd @ 15% O_2 and the use of an oxidation catalyst. This BACT specification is based upon several GE LM6000 gas turbine permits in the Bay Area. The District's BACT Guideline does not specify a "technologically feasible/cost-effective" CO emission concentration level. A review of the EPA RACT/BACT/LAER clearinghouse database initially identified a CO emission

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Part A - Policy and Procedures for Major Polluting Facilities; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/bactidx.htm May 2008 updates to BACT cost effectiveness thresholds (Final Staff Report).

[30] A limit of 4 ppm CO at 15% O2 was requested by Mariposa Energy in its January 27, 2010 letter to BAAQMD.

[31] Please see EIT Quote supplied by Mariposa Energy and CO Average Workbook.

[32] Please see EIT Quote supplied by Mariposa Energy and CO Incremental Workbook.

limitation of 1.8 ppm as the lowest BACT determination for the Wisconsin Electric Company – Germantown simple-cycle gas turbine abated by an oxidation catalyst. However, it should be noted that the emission limitation was reported in error and that the facility's Title V permit shows that the simple cycle turbine has CO emission limits of 25 ppmvd at 100 percent load and 100 ppmvd at 60 percent load.

Lastly, the District has determined that 2 ppm (1-hour average) is the most stringent BACT 2 emission limitation that has been proposed for this type of facility. However, the Marsh Landing Generating Station project has not been constructed. Therefore, the project has not demonstrated compliance with the proposed 2 ppm (1-hour average) limit.

TABLE 9. CO EMISSION LIMITS FOR LARGE SIMPLE-CYCLE POWER PLANTS USING OXIDATION CATALYSTS

Facility	**CO (ppmvd @ 15% O_2)**
Panoche Energy Center, SJVAPCD GE LMS100 Gas Turbines, 100 MW each	6 (3-hr)
Walnut Creek Energy Park, SCAQMD GE LMS100 Gas Turbines, 100 MW each	6 (1-hr)
Sun Valley Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	6 (1-hr)
CPV Sentinel Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	6 (1-hr)
Lambie Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	6 (3-hr)
Riverview Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	6 (3-hr)
Wolfskill Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	6 (3-hr)
Goosehaven Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	6 (3-hr)
Los Esteros Critical Energy Facility, BAAQMD GE LM6000 Gas Turbines, 49 MW each	4 (3-hr)
San Francisco Electric Reliability Project, BAAQMD GE LM6000 Gas Turbines, 49 MW each	4 (3-hr)
GWF Hanford Combined Cycle Power Plant*, SJVAPCD GE LM6000, 48 MW each	3 (3-hr)
GWF Henrietta Combined Cycle Power Plant*, SJVAPCD GE LM6000, 48 MW each	3 (3-hr)
Marsh Landing Generating Station, BAAQMD Siemens SGT6-5000F Gas Turbines, 190 MW each	2 (1-hr)

*Note: The GWF Hanford and Henrietta Combined Cycle Power Plant projects are currently being operated in simple cycle mode with a CO emission limit of 6.0 ppm. GWF plans to convert the simple cycle units to combined cycle by adding a once-through boiler which will allow the units to operate in both simple and combined cycle modes. The Hanford and Henrietta conversion projects were approved by the CEC in March 2010. Therefore, the combined cycle projects have not been completed and the LM6000 units have only demonstrated compliance with the 6.0 ppm emission limit.

CO BACT Determination

Based on the evaluation above, the proposed permit limit of 2 ppmvd CO @ 15% O_2 averaged over 3-hours would be lower than what has been achieved in practice for other simple-cycle gas turbines (BACT 2). Furthermore, the incremental cost associated with a 2 ppmvd CO @ 15% O_2 emission limit averaged over 1-hour, would be significantly higher than the incremental cost effectiveness threshold per ton of CO reduction (BACT 1).

Therefore, the District has determined that BACT for CO for this facility is the use of good combustion practice with abatement by an oxidation catalyst, and a permit limit of 2 ppmvd @ 15% O_2 averaged over a 3-hour period. This proposed BACT limit for CO is based on a review of the feasible, cost effective CO control technologies, and a review of comparable permit limits for simple-cycle gas turbines. CO exhaust gas concentrations will be continuously monitored by a CEM while the turbines are in operation.

5.5 Best Available Control Technology for Precursor Organic Compounds (POC)

The Precursor Organic Compound (POC) emissions from the simple-cycle gas turbines are subject to District BACT requirements since the potential to emit exceeds 10 pounds of POC per highest day. Similar to CO, the emissions of POC result from the incomplete combustion of fuels and the emissions control techniques for CO are also applicable to POC emissions from combustions sources. Therefore, the appropriate BACT control device or technique for CO is also an applicable BACT control device or technique for POC.

The District has reviewed the available control technologies in the BACT analysis for CO (equally applicable to POC) and determined that good combustion practice and abatement using an oxidation catalyst are the BACT technologies for controlling POC from the proposed simple-cycle combustion turbines at MEP.

Cost Effective and Feasible (BACT 1) POC Control Technologies for Simple-Cycle Gas Turbines

There is currently no technologically feasible or cost-effective specification for POC for simple-cycle turbines in the District BACT guidelines. However, the District BACT Guideline 89.1.3 specifies an achieved in practice BACT level for POC for simple-cycle gas turbines with an output rating > 40 MW as 2.0 ppmv, dry @ 15% O_2, which is typically achieved through the use of an oxidation catalyst. This is based upon several LM6000 gas turbine permits which were originally permitted with POC emission limits in pounds per hour or pounds per million Btu at 2.0 ppmvd @ 15% O_2.

Because the Marsh Landing Generating Station project recently proposed a POC permit limit of 1 ppm POC @ 15% O_2 averaged over 1 hour[33], the District considered whether a limit of 1 ppm POC averaged over one hour would also be feasible at this facility. Mariposa Energy provided a vendor quote that indicates controlling POC from the GE guarantee concentration of 3 ppmvd @ 15% O_2 to 1 ppmvd @ 15% O_2 would result in a capital cost of approximately $50,000 with an

[33] BAAQMD. "Preliminary Determination of Compliance for the Marsh Landing Generating Station". March, 2010.

increase in total back pressure on the combustion turbine of 0.2 inches of water column. The amount of POC reduction using these increased controls would be 2.34 tons per year, resulting in a total average cost effectiveness of approximately $20,100 per ton of POC reduced, based on an annualized cost of approximately $47,000.[34] Based on the District's cost effectiveness threshold of $17,500 per ton of POC, the increased control costs would exceed the cost effectiveness threshold and would not be considered cost effective.

Therefore, the District has determined that BACT 1 for the simple-cycle gas turbines for POC is the use of good combustion practice and abatement with an oxidation catalyst to achieve a 2.0 ppmvd @ 15% O_2 emission limit, or 1.2 lb per hour or 0.0025 lb/MMBtu.

Achieved in Practice (BACT 2) POC Emissions Limit for Simple-Cycle Gas Turbines

The District then evaluated what the appropriate BACT 2 emission limit should be for POC. The District reviewed permit limits from similar facilities, as summarized in **Table 10**.

[34] Please see EIT Email Dated May 18, 2010 supplied by Mariposa Energy and POC Average Workbook.

TABLE 10. POC EMISSION LIMITS FOR LARGE SIMPLE-CYCLE GAS TURBINES

Facility	POC (ppmvd @ 15% O_2)
Panoche Energy Center, SJVAPCD GE LMS100 Gas Turbines, 100 MW each	2 (3-hr)
Walnut Creek Energy Park, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2 (1-hr)
Sun Valley Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2 (1-hr)
CPV Sentinel Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2 (1-hr)
Lambie Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
Riverview Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
Wolfskill Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
Goosehaven Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
Los Esteros Critical Energy Facility, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
San Francisco Electric Reliability Project, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2 (1-hr)
GWF Hanford Combined Cycle Power Plant, SJVAPCD GE LM6000, 48 MW each	2 (3-hr)
GWF Henrietta Combined Cycle Power Plant, SJVAPCD GE LM6000, 48 MW each	2 (3-hr)
Progress Bartow Power Plant, Florida, Siemens SFT6-5000F Turbine, 195 MW	1.2
Marsh Landing Generating Station, BAAQMD Siemens SGT6-5000F Gas Turbines, 190 MW each	1 (1-hr)

*Note: The GWF Hanford and Henrietta Combined Cycle Power Plant projects are currently being operated in simple cycle mode with a POC emission limit of 2.0 ppm. GWF plans to convert the simple cycle units to combined cycle by adding a once-through boiler which will allow the units to operate in both simple and combined cycle modes. The Hanford and Henrietta conversion projects were approved by the CEC March 2010. Therefore, the combined cycle projects have not been completed and the LM6000 units have only demonstrated compliance with the 2.0 ppm emission limit.

The Pinellas County Department of Environmental Management's Air Division was contacted to discuss the Progress Bartow Power VOC emission rate of 1.2 ppmvd.[35] The Bartow facility permit included a 1,280 MW combined-cycle facility and a single 195 MW simple-cycle unit (both based

[35] See Mariposa Energy contact report for conversation with Pinellas County Department of Environmental Management's Air Division.

on the Siemens SGT6-5000F gas turbine) with the simple-cycle unit never being constructed. Therefore, the 1.2 ppm emission limit for the Progress Bartow Power Plant was not demonstrated in practice.

The District also evaluated whether the VOC emission rate of 1 ppm averaged over 1 hour would be an appropriate BACT 2 emission level for MEP. As previously discussed, the Marsh Landing project uses an industrial turbine technology as opposed to the aero-derivative technology proposed by MEP. As noted by GE, due to the design of the industrial turbines, the exhaust gases are at combustion temperatures for approximately twice the duration of the aero-derivative turbines.[36] The fact that the industrial turbine combustion gases are at combustion temperatures for twice the duration results in a reduction in POC emissions over an aero-derivative combustion turbine. Furthermore, the industrial combustion turbines have longer combustion residence times due to their larger volume combustion systems. This advantage is primarily associated with the origins of each combustion turbine technology, with aero-derivative turbines originating from the aviation industry and industrial turbines designed solely for the power generation industry.[37] Lastly, typical emission controls for NOx involve the reduction of combustion temperatures to minimize the formation of NOx, which tends to increase the formation of CO and POC. The combination of reduced combustion temperatures (to control NOx formation) and reduced residence times (i.e., the time the combustion gases are at combustion temperatures in the combustion system) tends to reduce the complete conversion (oxidation) of hydrocarbons in the fuel to carbon dioxide and water. Therefore, based on these technological differences, the District has concluded that a 1.0 ppmvd @ 15% O_2 emission limit averaged over 1-hour would not be appropriate for MEP.

<u>POC BACT Determination</u>

The District has reviewed the POC permit emissions limits for similar facilities shown in Table 10 and determined that 1 ppm POC @ 15% O_2 averaged over 1-hour is the lowest permitted emissions limit for a utility-scale simple-cycle gas turbine abated by an oxidation catalyst. However, based on the technological differences between the industrial frame and aero-derivative technologies, the District has concluded that a 2.0 ppmvd @ 15% O_2 emission limit for the MEP would be an appropriate BACT 2 emission limit. Furthermore, based on the cost effectiveness evaluation, the cost effectiveness of requiring the MEP to meet 1.0 ppm averaged over 1 hour would be $21,900 per ton of POC removed and would not be considered cost effective based on the District's published Maximum Cost Guidelines for BACT.[38] Therefore, the District has determined that BACT for MEP would be a 2.0 ppmvd @ 15% O_2 emission limit averaged over 1 hour.

5.6 Best Available Control Technology for Particulate Matter (PM)

For emissions of particulate matter (PM), the District is proposing the use of PUC-quality low-sulfur natural gas, inlet filtration, and good combustion practices as BACT control technologies. The District is also proposing a BACT PM emission limit of 2.5 lb/hr. This emissions limit is based

[36] General Electric, "VOC Emissions from LM6000 for Mariposa Energy, LLC", page 2.
[37] General Electric, "VOC Emissions from LM6000 for Mariposa Energy, LLC", page 2.
[38] BAAQMD BACT Workbook Policy and Implementation Procedure, Interpretation of BACT.

on a review of permit limits and emissions data from other similar simple-cycle natural gas fired combustion turbines. The District's proposed BACT determination is explained below.[39]

The turbine vendor (GE) has provided documentation which concludes that the combustion process by itself does not play a major role in PM formation from natural gas combustion in a gas turbine.[40] Rather, GE states the major sources of natural gas-fired gas turbine PM emissions are the following four sources:

1. Fuel Sulfur conversion to sulfates and ammonium sulfates.

2. Particulate matter in the ambient air that enters the gas turbine through the inlet air filtration system, SCR tempering air, and aqueous ammonia dilution air.

3. Contaminants contained in the water used for the NOx control and power augmentation SPRINT systems.

4. Particulate matter measurement uncertainties.

The four sources are explained in further detail below.

Fuel sulfur is converted to oxides of sulfur, primarily sulfur dioxide and sulfate. The catalysts used to control NOx and CO emissions are also capable of converting fuel sulfur to sulfates. GE estimates that the gas turbine, oxidation catalyst, and SCR convert approximately half of the fuel sulfur to sulfates and ammonium salts, contributing to the formation of particulate matter.[41]

Any particles that enter the combustion turbine through the inlet air will be emitted at the stack as PM. Because gas turbines consume a significant volume of ambient air, inlet air filtration is applied to minimize degradation of gas turbine performance/efficiency and life[42][43] and minimize

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[39] This facility is subject to BACT requirements for PM10 only. PM2.5, a subset of PM10, is regulated under federal requirements in 40 C.F.R. Section 52.21 (PSD) and 40 C.F.R. Part 51, Appendix S (Non-Attainment NSR). The facility is not subject to PSD or PM2.5 Non-Attainment NSR permit requirements under Section 52.21 or Appendix S because the facility is not a "major facility" for the purposes of these regulations. The District is therefore not conducting a PSD permitting analysis or an Appendix S permitting analysis for PM2.5. For a detailed discussion of the applicability of these federal requirements for PM2.5, see Section 7 below. The District notes, however, that for combustion turbines essentially all of the PM emissions are less than one micron in diameter, so it is both PM10 and PM2.5. (See AP-42, Table 1.4-2, footnote c, 7/98 (available at www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf). Moreover, the same emissions control technologies that will be effective for PM10 for this facility will also be similarly effective for PM2.5. The District's BACT analysis and emissions limit for PM10 will also therefore effectively be a BACT limit on PM2.5 emissions as well, even though the facility is not subject to the federal PM2.5 BACT requirements as discussed in Section 7.

[40] General Electric, "PM10 Emissions from LM6000 for Mariposa Energy, LLC", page 2.

[41] General Electric, PM10 Emissions from LM6000 for Mariposa Energy, LLC, Appendix A.

[42] General Electric Global Projects Operation, Particulate Matter, PM10 and PM2.5: What is it, How is it Regulated, How is it Measured, and What is GE's Position on PM emission from Gas Turbines? September 3, 2009, page 6.

particulate matter emissions in the exhaust. Furthermore, performance degradation occurs due to fouling of the compressor blades, which in extreme cases can reduce turbine output by 20 percent. GE's high efficiency inlet air filters can reduce inlet air concentrations of particulate matter smaller than 1 micron in diameter by up to 95 percent.[44]

As with the ambient air consumed by the gas turbine, impurities in the water used for NOx control and power augmentation (Spray Inter-Cooled Turbine or SPRINT) can contribute to particulate matter emissions. These impurities are in the form of total suspended and dissolved solids (found in all water). However, conformance with GE's water specification minimizes the potential particulate matter formation by keeping impurities in the NOx water injection and SPRINT water at very low levels.[45]

GE also notes the difficulty of measuring PM from a combustion turbine and the requirement to extend typical PM tests in order to collect a quantifiable amount of PM. Furthermore, GE notes the current PM measurement method (EPA Reference Methods 202) has a positive bias due to artifacts of the testing method, as SO_2 is converted then measured as PM. This testing bias is also discussed in the EPA preamble to the March 25, 2009 proposal to revise the PM sampling methodology to "revise the sample collection and recovery procedures of the method to reduce the formation of reaction artifacts that could lead to inaccurate measurements of condensable particulate matter (CPM) minimize sampling/analytical errors due to the conversion of SO_2 to sulfate species in the sampling system."[46] Given the inherently low combustion-related PM formation, any artifact PM formation leads to wide variations in accuracy of the PM measurements.

Taking into account the considerations noted above, GE indicates that their PM emission guarantees are based on a 97.5 percent pass rate with an 85 percent confidence interval, meaning GE predicts with 85 percent confidence that the PM emission rate would be less than the emission guarantee level 97.5 percent of the time.[47] GE's standard PM emission rate guarantee for the LM6000PC SPRINT is 3.0 pounds per hour (lb/hr) and GE offers a reduced PM emission rate of 2.5 lb/hr for an increased cost to account for the financial risk associated with a lower emission guarantee.

<u>Cost Effective and Feasible (BACT 1) PM10 Control Technologies for Simple-Cycle Gas Turbines</u>

As with the other pollutants addressed above, control technologies for PM can be grouped into two categories: (1) combustion controls, and (2) post-combustion controls.

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[43] General Electric Power Generation, Gas Turbine Inlet Treatment (GER-3419A), page 1.
[44] General Electric Power Generation, Gas Turbine Inlet Treatment (GER-3419A), page 7 and Figure 7.
[45] GE Energy, Requirements for Water and Steam Purity for Injection in Aero Derivative Gas Turbines (MID-TD-0000-3), June 2004.
[46] Preamble to the March 25, 2009 Proposal to Revise EPA Reference Method 202.
[47] General Electric, "PM10 Emissions from LM6000 for Mariposa Energy, LLC", page 7.

Combustion Controls

- **Good Combustion Practice:** The District has identified good combustion practices as an available combustion control technology for minimizing unburned hydrocarbon formation during combustion. Good combustion will ensure proper air/fuel mixing ratios to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack. In addition to good combustion, use of high efficiency filtration on the inlet air and SCR tempering air minimizes the formation of PM. Similarly, use of high quality water for NOx control and power augmentation (SPRINT) also minimizes PM emissions.

- **Clean-burning fuels:** The use of clean-burning fuels, such as natural gas which has only trace amounts of sulfur, will result in minimal formation of PM during combustion. The use of natural gas is commercially available and demonstrated for the MEP gas turbines.

- **Dry Low-NOx Combustor:** The use of a Dry Low-NOx Combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable PM. Dry Low-NOx Combustors are in wide use on utility scale natural gas fired gas turbines.

- **Water Injected Combustor:** The use of a water injected combustor also provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable PM. Water injected combustors are in wide use on utility scale natural gas fired gas turbines.

Post-Combustion Controls

- **Electrostatic precipitators:** Electrostatic precipitators are used on solid fuel boilers and incinerators to remove PM from the exhaust. Electrostatic precipitators use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Solid particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particles into collection hoppers. However, this technology is not effective for control of low concentration fine particulate matter (PM2.5) sources, or sources with high condensable particulate matter (sulfates and ammonium salts).

- **Baghouses:** Baghouses are used to collect PM by drawing the exhaust gases through a fabric filter. Particulates collect on the surface of filter bags that are periodically distorted by shaking, reverse air or pulse jets to release the particulates into hoppers. While high temperature bag fabrics have been developed, the upper limit of baghouse operating temperatures are below 500°F and would require further tempering of the exhaust gases to reduce the temperature to levels that would allow a baghouse to operate without damaging the bags.

Therefore, with respect to combustion controls, good combustion practice, clean-burning fuels, and inlet air filtration are common control devices/techniques that are technically feasible for simple-cycle natural gas fired combustion turbines and are often used to control emissions from sources of this type.

With respect to the post-combustion controls – electrostatic precipitators and baghouses – these control devices are not proven to be technically feasible and cost effective for natural gas fired combustion turbines. These devices are normally used on solid/liquid-fuel fired or other types of sources with high PM emission concentrations, and are not used in natural gas fired applications which have inherently low PM emission concentrations. The District is not aware of any natural gas fired combustion turbine that has ever been required to use add-on controls such as these. The District also reviewed the EPA BACT/LAER Clearinghouse and confirmed that EPA has no record in that database of any post-combustion particulate controls that have been required for natural gas fired gas turbines.

Furthermore, if add-on control equipment were installed, it would create significant back pressure that would significantly reduce the efficiency of the plant and would cause more emissions per unit power produced. Moreover, these devices are designed to be applied to emissions streams with far higher particulate emission concentrations, and they would have very little effect on the low-PM emission concentration sources from this facility in further reducing PM emissions. It takes an emission source with a much higher PM concentration (or grain loading – grains/standard dry cubic foot of exhaust gas) for these types of add-on abatement devices to operate efficiently[48]. The low level of abatement efficiency (if any) for controlling PM from a natural gas fired combustion turbine would not be cost-effective, even if they could feasibly be applied to this type of source. For all of these reasons, the District has determined that post-combustion particulate control devices are not technologically feasible or cost effective (BACT 1) for the proposed MEP turbines.

Finally, the California Public Utilities Commission (PUC) has a regulatory standard for pipeline natural gas fuel sulfur content of less than 1.0 grains of sulfur per 100 scf. This PUC standard is maximum sulfur content at any point in time.[49] Therefore, the use of pipeline natural gas meets the low sulfur requirement for clean burning fuel.

Therefore, the District has determined that BACT 1 is good combustion practices (low NOx combustors), clean burning low sulfur fuels, and inlet filtration.[50] This BACT 1 determination is also consistent with District BACT Guideline 89.1.3, which specifies BACT for PM10 for simple-cycle gas turbines with rated output of > 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of less than 1.0 grain per 100 scf.

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[48] For example, if a baghouse were installed on the turbines, the turbine exhaust at the inlet to the baghouse would contain less PM than is normally seen in baghouse output, after abatement. PM Emissions from a baghouse are normally in the range 0.0013 to 0.01 grains per standard cubic foot (see BAAQMD BACT/TBACT Workbook, Section 11: Miscellaneous Sources), whereas PM emissions from the proposed MEP turbines would be 0.001 gr/dscf (@ 15% O2).

[49] The 1.0 grain per 100 scf PUC standard is the maximum sulfur content of the gas at any point in time. The actual average content is expected to be less than 0.25 grains per 100 scf. The District has based its calculations of annual emissions on this 0.25 grain per 100 scf average sulfur content. Note that a portion of the sulfur contained in natural gas is intentionally added as an odorant to allow for the detection of leaks which would be a safety concern.

[50] Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999, pg. 34.

Achieved in Practice (BACT 2) PM Emissions Limit for Simple-Cycle Gas Turbines

In addition to the determination of what control devices and techniques are technically feasible and cost effective (BACT 1) for this proposed facility, the District is also proposing to implement a numerical PM achieved in practice (BACT 2) emission limitation based on the most stringent mass emission rate limitation achieved for a natural gas fired simple-cycle combustion turbine facility such as this one pursuant to District Regulation 2-2-206.2. The District is considering a PM emissions limit of 2.5 lb/hr. This limit also corresponds to emissions of 60 pounds per day (per turbine), and 0.0012 grains per dry standard cubic foot (15% O_2) of natural gas. The proposed emissions limit would be as stringent as any other PM emission limitation achieved in practice by any other similar natural gas fired simple-cycle combustion turbine source.

Based on the PM paper prepared by GE, an emission limitation based on heat input is inappropriate as GE believes that fuel combustion does not play a major role in natural gas-fired combustion turbine PM formation.[51] Therefore, an emission limit in pounds per million Btu (lb/MMBtu) is not considered.

To evaluate whether this proposed limit satisfies the District's BACT 2 requirement, the District compared it with emission limits and performance data from other similar-sized natural gas fired simple-cycle combustion turbines. **Table 11** below presents PM permit limits for projects similar to the simple-cycle gas turbines proposed for the MEP in descending order by emission rate in pounds per hour basis.

[51] General Electric, "PM10 Emissions from LM6000 for Mariposa Energy, LLC".

TABLE 11. RECENT BACT PM_{10} PERMIT LIMITS FOR LARGE SIMPLE-CYCLE GAS TURBINES

Facility	PM10 (lb/hr)	Size (MW)
Lambie Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	3.0	49
Riverview Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	3.0	49
Wolfskill Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	3.0	49
Goosehaven Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	3.0	49
Gilroy Energy Center, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5	49
Los Esteros Critical Energy Facility, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5	49
San Francisco Electric Reliability Project, BAAQMD GE LM6000 Gas Turbines, 49 MW each	2.5	49
Canyon Power Plant, SCAQMD, GE LM6000 Gas Turbines, 49 MW each	2.5	49
GWF Hanford Combined Cycle Power Plant*, SJVAPCD GE LM6000 PC SPRINT, 48 MW each	2.2	48
GWF Henrietta Combined Cycle Power Plant*, SJVAPCD GE LM6000 PC SPRINT, 48 MW each	2.2	48

*Note: The GWF Hanford and Henrietta Combined Cycle Power Plant projects are currently being operated in simple cycle mode with a PM_{10} emission limit of 3.0 lb/hr. GWF plans to convert the simple cycle units to combined cycle by adding a once-through boiler which will allow the units to operate in both simple and combined cycle modes. The Hanford and Henrietta conversion projects were approved by the CEC March 2010. Therefore, the combined cycle projects have not been completed and the LM6000 units have only demonstrated compliance with the 3.0 lb/hr emission limit.

Based on this review of permit limits for similar simple-cycle natural gas fired turbines, the District has determined that there are two facilities (GWF Hanford and Henrietta Combined Cycle Power Plants) with permit limits that are more stringent than the 2.5 lb/hr limit the District is proposing for the MEP. However, these units have only recently completed the permitting process for conversion from simple cycle units to combined cycle mode.[52] As such, these units have not demonstrated that they can consistently achieve this emission rate.

To determine if a lower PM10 emission rate than 2.5 lb/hr has been achieved in practice (BACT 2), the District also reviewed PM source test data for a number of comparable GE LM6000 simple-cycle gas turbines abated by an oxidation catalyst and SCR. These data are shown in **Table 12** below. As noted by GE, the use of the emission rates in pounds per million Btu (lb/MMBtu) would not be appropriate since only a minimal amount of PM emissions are directly correlated with natural gas consumption during the combustion process itself. Rather the turbine exhaust PM emissions are more closely dependent on the particulate concentration in ambient air, the impurities in the water used for NOx control and power augmentation, and the variability inherent in the sampling method.

[52] http://www.energy.ca.gov/sitingcases/hanford_amendment/index.html and http://www.energy.ca.gov/sitingcases/henrietta_amendment/index.html

TABLE 12. SUMMARY OF GENERAL ELECTRIC LM-6000 SIMPLE-CYCLE GAS TURBINE PARTICULATE EMISSIONS DATA.

Facility	Test Date	Source	PM lb/hour	PM FH lb/hour	PM BH lb/hour	Front %	Back %	Reported PM lb/MMBtu
Creed Energy Center	1/31/2003	S-1	2.18	1.05	1.13	48.2	51.8	0.0047
Creed Energy Center	7/6/2006	S-1	1.363	0.553	0.81	40.6	59.4	0.0028
Creed Energy Center	5/7/2009	S-1	0.6746	0.1948	0.4798	28.9	71.1	0.0012
Lambie Energy Center	1/16/2003	S-1	1.9	0.56	1.34	29.5	70.5	0.0042
Lambie Energy Center	5/5/2006	S-1	2.104	1.429	0.674	67.9	32.0	0.0039
Lambie Energy Center	5/11/2009	S-1	0.83	0.3488	0.4807	42.0	57.9	0.0016
Los Esteros Energy	7/26-7/27/05	S-1	2.266	1.016	1.25	44.8	55.2	0.0042
Los Esteros Energy	7/26-7/27/05	S-2	0.896	0.363	0.533	40.5	59.5	0.0016
Los Esteros Energy	7/28/2005	S-3	1.44	0.578	0.862	40.1	59.9	0.0025
Los Esteros Energy	7/27-7/29/05	S-4	0.915	0.326	0.589	35.6	64.4	0.0016
Los Esteros Energy	9/8/2006	S-1	0.775	0.307	0.468	39.6	60.4	0.0015
Los Esteros Energy	9/8/2006	S-2	0.871	0.331	0.54	38.0	62.0	0.0015
Los Esteros Energy	9/6-9/7/06	S-3	1.805	0.398	1.407	22.0	78.0	0.0033
Los Esteros Energy	9/6-9/7/06	S-4	0.904	0.318	0.586	35.2	64.8	0.0017
Los Esteros Energy	7/25-7/26/07	S-1	1.672	0.967	0.705	57.8	42.2	0.0030
Los Esteros Energy	7/25-7/26/07	S-2	1.429	0.541	0.888	37.9	62.1	0.0025
Los Esteros Energy	7/24-7/25/07	S-3	1.456	0.666	0.79	45.7	54.3	0.0025
Los Esteros Energy	7/24-7/25/07	S-4	1.646	0.973	0.673	59.1	40.9	0.0027
Los Esteros Energy	5/29-5/30/08	S-1	1.4145	0.6957	0.7189	49.2	50.8	0.0026
Los Esteros Energy	5/28-5/29/08	S-2	0.9769	0.3191	0.6578	32.7	67.3	0.0018
Los Esteros Energy	5/28-5/29/08	S-3	1.49	0.4393	1.0555	29.5	70.8	0.0027
Los Esteros Energy	5/29-5/30/08	S-4	2.21	1.345	0.8629	60.9	39.0	0.0041
Los Esteros Energy	5/13/2009	S-1	1.16	0.4811	0.68	41.5	58.6	0.0020
Los Esteros Energy	5/14-5/15/09	S-2	0.969	0.4702	0.4983	48.5	51.4	0.0018
Los Esteros Energy	5/14-5/15/09	S-3	0.864	0.4082	0.4561	47.2	52.8	0.0016
Los Esteros Energy	5/13-5/14/09	S-4	1.04	0.3226	0.7186	31.0	69.1	0.0019
Riverview	5/8/2009	S-1	1.469	0.789	0.68	53.7	46.3	0.0030
Wolfskill	6/2/2004	S-1	2.15	1.3	0.85	60.5	39.5	0.0047
Wolfskill	7/5/2006	S-1	1.9	0.582	1.319	30.6	69.4	0.0034
Wolfskill	5/4/2009	S-1	0.81	0.29	0.52	35.8	64.2	0.0010
Gilroy Energy Center	7/19/2005	S-3	1.9					0.0029
Gilroy Energy Center	7/21/2005	S-4	1.7					0.0022
Gilroy Energy Center	7/21/2005	S-5	1					0.0016
Gilroy Energy Center	5/23/2006	S-3	1.69					0.0020
Gilroy Energy Center	5/24/2006	S-4	0.95					0.0010
Gilroy Energy Center	5/22/2006	S-5	1.41					0.0020
Gilroy Energy Center	5/23/2007	S-3	1.6	0.6132	0.9856	38.3	61.6	0.0030
Gilroy Energy Center	5/24/2007	S-4	1.25	0.5443	0.7016	43.5	56.1	0.0019
Gilroy Energy Center	5/25/2007	S-5	1.6	0.6769	0.9193	42.3	57.5	0.0027
Goosehaven	1/23/2003	S-1	2.44					0.0047
Goosehaven	7/6/2006	S-1	2.44	1.327	1.112	54.4	45.6	0.0040
Goosehaven	5/6/2009	S-1	0.97	0.1481	0.8235	15.2	84.8	0.0017
		Average	1.44	0.62	0.79	41.9	58.0	
		Maximum	2.44	1.43	1.41	67.9	84.8	

Notes: All of these facilities use an oxidation catalyst to reduce CO emissions and an SCR system to reduce NOx emissions, consistent with the proposed MEP.

Table 12 shows that PM emissions from the LM6000 units can be highly variable, with the minimum, average, and maximum PM emission rates of 0.67, 1.44, and 2.44 lb/hr, respectively. These source test data correlate reasonably well with GE's statistical analysis that indicates an expected median PM emissions of 1.47 lb/hr for the LM6000. GE's analysis assumed a sampling uncertainty of 0.7 lb/hr, a fuel sulfur content of 0.65 grains/100 standard cubic foot (gr/100 SCF), and concluded that most LM6000 can achieve a PM emission rate of less than 2.99 lb/hr. GE's analysis also determined that lowering the fuel sulfur content to 0.25 gr/100 SCF shows that most LM6000 can achieve a PM emission rate of 2.48 lb/hr. Therefore, GE concludes that fuel sulfur content and PM measurement uncertainties affect its ability to guarantee emissions below 2.5 lb/hr.[53]

In order to further examine if a PM emission limit below 2.5 lb/hr is feasible, Mariposa Energy conducted a statistical analysis of the source test data presented in Table 12 to determine the potential of achieving a PM emission rate lower than 2.5 lb/hr.[54] The analysis was based on the 85% confidence interval with 97.5% pass rate criteria used by GE to establish an emission guarantee for the LM6000 turbines.[55] The results of this statistical analysis show that, of the source tests presented in Table 12, it can be predicted with 85 percent confidence that the percent of exceedances of the 2.0 lb hour PM emission rate would be between 10.6 and 24.7 percent. Conducting the same analysis for a PM limit of 2.2 lb/hr predicts that between 4.9 and 16.6 percent of the facilities would exceed 2.2 lb/hr at an 85 percent confidence interval. Therefore, it is concluded that a PM emission limit less than 2.5 lb/hr has not been achieved in practice (BACT 2) based on the source test data analyzed by the District.

Particulate Matter BACT Determination

The District has determined that the use of low sulfur natural gas combined with good combustion practice is BACT for PM. The District is also proposing a PM BACT emissions limit of 2.5 lb/hour, based on a review of permit limits and source test data from other simple-cycle gas turbines.

5.7 Best Available Control Technology for Sulfur Dioxide (SO_2)

The potential emissions of SO_2 from the simple-cycle gas turbines exceed 10 lb per highest day for each turbine. These sources are therefore subject to District BACT requirements for SO_2.

Cost Effective and Feasible SO_2 Control Technologies for Simple-Cycle Gas Turbines

There are two primary mechanisms used to reduce SO_2 emissions from combustion sources: (i) reduce the amount of sulfur in the fuel, and (ii) remove the sulfur from the combustion exhaust gases.

[53] General Electric, "PM10 Emissions from LM6000 for Mariposa Energy, LLC", page 3a and Figures 1 and 3a.
[54] CH2M HILL Statistical Analysis Technical Memorandum, April 19, 2010.
[55] General Electric, "PM10 Emissions from LM6000 for Mariposa Energy, LLC", page 7.

Limiting the amount of sulfur in the fuel is a common practice for natural gas fired power plants. Such plants in California are typically required to combust only California PUC grade natural gas with a sulfur content of less than 1 grain per 100 standard cubic feet (scf). This control technique has been achieved in practice at other facilities (BACT 2), and it is technologically feasible and cost-effective (BACT 1). The District is therefore proposing to require the use of PUC-grade natural gas with a sulfur content of less than 1 grain/100 scf as a BACT control technique for SO_2.

Add-on controls that remove sulfur from the combustion exhaust, such as flue gas desulfurization, are not feasible for natural gas fired power plants and have not been used at such facilities. These types of control devices are typically installed on coal fired power plants that burn fuels with much higher sulfur contents. There are two main types of SO_2 post-combustion control technologies: wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases and may remove up to 90% of the SO_2 from the exhaust stream. Dry scrubbers use an SO_2 sorbent injected as a powder or slurry to remove the SO_2 and the SO_2 and sorbent are removed by a particulate control device. The abatement efficiencies vary with different types of dry scrubbing technologies, but are generally lower than efficiencies for wet scrubbing technologies. These technologies are not feasible for combustion sources burning low sulfur content natural gas. The SOx concentrations in the natural gas combustion exhaust gases are too low (less than 1 ppm) for the scrubbing technologies to work effectively or be technologically feasible and cost effective. These control technologies require much higher sulfur concentrations in the combustion exhaust gases to become feasible as a control technology. For this reason, they have not been used at natural gas fired power plants such as the proposed Marsh Landing facility. As these control technologies have not been achieved in practice at other similar facilities and are not technologically feasible here, the District is not proposing to require them as BACT for this facility.

Achieved in Practice SO_2 Emissions Limit for Simple-Cycle Gas Turbines

Fuel sulfur limits are therefore the only feasible SO_2 control technology for natural gas combustion sources, and the District is proposing to require this technology as BACT. The District is proposing BACT permit limits based on the PUC natural gas specification of a maximum of 1 grain of sulfur per 100 scf of natural gas. The permit limits are based on maximum sulfur content of the fuel and are expressed in units of pounds per hour, pounds per unit of natural gas burned (MMBtu), and pounds per day of SO_2. The emission calculations are shown in the Appendix A.

SO2 BACT Determination

This proposed BACT determination is consistent with the District's BACT Guidelines for SO_2. District BACT Guideline 89.1.3 specifies BACT 2 for SO_2 for simple-cycle gas turbines with an output rating of > 40 MW as the exclusive use of clean-burning natural gas with a sulfur content of less than 1.0 grain per 100 scf.

5.8 Best Available Control Technology for Startups, and Shutdowns

Startup and shutdown periods are a normal part of the operation of natural gas-fired power plants. They involve emissions rates that are highly variable and greater than emissions during steady-state operation. Emissions are greater during startup and shutdown for several reasons. One reason is that during startup and shutdown, the turbines are not operating at full load where they are most efficient. Another reason is that the exhaust temperatures are lower than during steady-state operations. Post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function optimally at lower temperatures, and so there may be partial or no abatement for NOx, carbon monoxide and precursor organic compounds for a portion of the startup period.[56]

Compared to combined cycle turbine systems, simple-cycle turbines can quickly come up to full load. This is one reason that they are used to provide peaking load duty with the capability to rapidly accelerate to synchronous speed, synchronize with the grid, ramp up to 100 percent load, and then down to zero load. In contrast, the combined-cycle systems include waste heat recovery and steam-generating components. Therefore, they take more time to come up to full operating temperature.

Because emissions are greater during startups and shutdowns than during steady-state operation, the BACT limits established in the previous sections for steady-state operations are not technically feasible during these periods. The District is therefore establishing separate BACT limits representing the most stringent emissions limits that have been achieved-in-practice or technologically feasible and cost-effective for this type of facility. To do so, the District has conducted an additional BACT analysis specifically for startups and shutdowns.

Control Devices and Techniques to Limit Startup and Shutdown Emissions:

The available approach to reducing startup and shutdown duration from simple-cycle turbines is to use best work practices[57]. By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown event to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions.

[56] Note that emission rates of particulate matter and sulfur oxide emissions are not affected by startups and shutdowns and are conservatively estimated to be the same as for full load operation (2.5 lb/hour for particulate matter, 1.35 lb/hour for SOx maximum, 0.34 lb/hour SOx annual average).

[57] The lack of additional control technologies for simple-cycle turbines is different than with combined-cycle turbines. For combined-cycle turbines, there have been several technological advances that have recently been developed, or are currently under development, that will allow those types of turbines to start up more quickly and with fewer emissions. These include startup procedures that heat up the additional steam-generating equipment used in combined-cycle turbines more quickly, allowing them to reach their optimal operating temperature more quickly; and advances that reduce emissions at lower loads where combined-cycle turbines must operate for extended periods while waiting for the equipment to heat up. These types of advances are not applicable to simple-cycle turbines. Simple-cycle turbines do not have any additional steam generating equipment that needs to be warmed up; and they ramp up very quickly to full load at rates as high as 10 MW per minute and do not spend any significant time operating at lower loads during startups.

Determination of BACT Emissions Limit for Startups and Shutdowns:

The District is proposing numerical emissions limits for startups and shutdowns to implement the BACT requirement here. The proposed limits for each operating scenario are outlined below.

Startups

During the first 2 minutes of a start up event, the LM6000 combustion turbine is operated without the introduction of fuel as a safety measure. After the 2 minute purge cycle, fuel is introduced and the combustion turbine load is increased until water injection is employed, which is approximately 6 minutes into the startup. From minute 6 to minute 10, the combustion turbine load is increased to 100% load. Emissions during this initial 10 minute startup period are expected to be 3.5 pounds of NOx, 3.0 pounds of CO, and 0.058 pounds of POC.[58] Initial startup emissions are summarized in **Table 13**. From minute 10 to minute 30, the SCR and oxidation catalyst are warmed to operating temperatures. When the nominal SCR catalyst temperature is reach, ammonia injection will commence to control NOx emissions. When the oxidation catalyst reaches nominal operating temperature, CO and POC reductions will commence.

TABLE 13. SIMPLE-CYCLE GAS TURBINE STARTUP EMISSION ESTIMATES

Pollutant	**Initial Startup - Estimated Emissions (pounds per turbine per startup)**
NO_x (as NO_2)	3.5
CO	3.0
POC	0.058

The initial startup emissions are minimal due to the short duration of the typical start time and due to the quick turbine ramp rate that minimizes low-load operation during startup. However, these emission estimates are not guaranteed emission rates for every startup. Moreover, startup emissions are highly variable, and it is expected that it will take up to 30 minutes for the SCR and oxidation catalyst to reach a stable temperature and become fully functional. An allowance for the CEM system lag of several minutes to relay compliant NOx and CO CEM readings and an allowance for the ammonia injection rate to stabilize with NOx concentration are other factors which influence the startup duration and can lead to longer startup times.

The District estimates over the 30-year life of the facility that a given startup may take as long as 30 minutes to allow the gas turbine and post combustion controls to reach steady-state operation. The District is therefore proposing to establish the not-to-exceed BACT limit for startups at 30 minutes to provide an adequate compliance margin that allows the operators to make appropriate adjustments to system controls in response to system operational conditions. This is the shortest time limit that the turbines can reasonably be expected to meet BACT levels under all operating conditions over the life of the equipment. Individual startups may be shorter than this proposed 30-

[58] "Estimated NOx, CO, and VOC Concentrations during a 10 Minute Start-up at ISO Conditions", GE LM6000, PC Sprint Printout.

minute limit, but an enforceable BACT permit limit must provide 30 minutes to allow an adequate margin of compliance to ensure that the equipment can consistently meet the limit.

The District has, therefore, conservatively estimated the emissions that would result from a 30-minute startup at 14.2 pounds of NOx, 14.1 pounds of CO, and 1.1 pounds of POC, which the District is proposing as BACT limits on the emissions from startups. The emissions were calculated assuming the SCR and oxidation catalyst would be fully functional within 30 minutes of initiating a startup.[59] Using this approach, the calculated maximum emission rates for startups are set forth in **Table 14**.

TABLE 14. PROPOSED STARTUP EMISSION LIMITS FOR A 30 MINUTE STARTUP

Pollutant	Maximum Startup Emissions (pounds per turbine per startup)
NO_x (as NO_2)	14.2
CO	14.1
POC	1.1

In addition, in order to protect hourly air quality standards, the District is also proposing an additional hourly limit for operating hours during which startups occur. This limit is based on a reasonable need for the facility to start up and shut down within a one-hour period, which is not unforeseeable given the facility's operation as a peaker facility. The District is basing this proposed limit on one 30 minute startup event, with a typical emissions profile as summarized in **Table 14** above, one shutdown with a typical emissions profile as summarized in Table 16 below (lasting 15 minutes), and the remainder of the hour with emissions within the steady-state BACT emissions limits. These maximum hourly emissions for hours with startups are summarized in **Table 15** below.

TABLE 15. MAXIMUM HOURLY PERMIT LIMITS FOR HOURS WITH STARTUPS

Pollutant	Maximum Startup Emissions (lb/hour)[b]
NO_x (as NO_2)	18.5
CO	18.1
POC	1.6

The District has concluded that using best work practices, the proposed simple-cycle gas turbines will be able to meet the startup permit limits shown above. The basis for these limits is emissions information provided by the gas turbine manufacturer (GE).

[59] Mariposa Energy to BAAQMD. January 27, 2010. See Attachment Table 5.1B.3R.

Shutdowns

GE also supplied the following emission estimates for a typical shutdown event occurring over 8 minutes.[60] The shutdown process begins with the combustion turbine reducing load for approximately 3 minutes when the water injection is discontinued. From minute 3 to minute 8, the turbine load is reduced and the introduction of fuel is discontinued.

TABLE 16. SIMPLE-CYCLE GAS TURBINES SHUTDOWN EMISSION ESTIMATES

Pollutant	**Typical Shutdown - Estimated Emissions (pounds per turbine per shutdown)**
NO_x (as NO_2)	2.7
CO	2.4
POC	0.047

The District proposes to have maximum pound-per-event limits for shutdowns. The District estimates over the 30-year life of the facility that a given shutdown may take as long as 15 minutes to allow the gas turbine time to ramp down from full load operation and allow time for the turbine to decelerate after fuel flow stops. Each shutdown would be limited to a maximum of 15 minutes for a worst-case shutdown.

The District then conservatively estimated the emissions during a 15-minute shutdown using an approach similar to the approach for estimating maximum startup emissions above. It was conservatively assumed that emissions from a typical shutdown, as summarized in Table 16, would occur over the final 8 minutes of the shutdown, and that the rest of the 15 minute shutdown period had emissions at normal steady-state emissions rates. These are the worst-case pound-per-event values for the simple-cycle gas turbines during a shutdown.

Thus, the District has concluded that using best work practices, the proposed simple-cycle gas turbines will be able to meet the permit limits shown above in **Table 14**, **Table 15** and **Table 17.**

TABLE 17. SIMPLE-CYCLE GAS TURBINES PROPOSED SHUTDOWN PERMIT LIMITS

Pollutant	**Maximum Shutdown Emissions (pounds per turbine per startup)**
NO_x (as NO_2)	3.2
CO	2.7
POC	0.2

[60] "Estimated NOx, CO, and VOC Concentrations During a 8 Minute Shutdown at ISO Conditions", GE LM6000, PC Sprint Printout

Conclusion

The District is proposing stringent emission limits for startups and shutdowns that can reasonably be achieved by the proposed MEP, based on a review of the gas turbine supplier's emission estimates. Emissions from specific startup and shutdown events may be significantly less than the proposed not-to-exceed permit limits, given the great variability of such events. The District is proposing to require the limits described above as the enforceable BACT limits to ensure that emissions are minimized to the greatest extent feasible while ensuring that the limits are achievable under all operating circumstances.

5.9 Best Available Control Technology during the Commissioning of Simple-Cycle Gas Turbines

The simple-cycle gas turbines and associated equipment are highly complex and have to be carefully tested, adjusted, tuned and calibrated after the facility is constructed. These activities are generally referred to as "commissioning" of the facility. During the commissioning period, each of the combustion turbine generators need to be fine-tuned at zero load, partial load, and full load to optimize its performance. The water injection control system used to control NOx emissions also need to be tuned to ensure that the turbines run efficiently while meeting both the performance guarantees and emission guarantees. In addition, the selective catalytic reduction (SCR) systems and oxidation catalysts need to be installed and tuned.

The simple-cycle gas turbines will not be able to meet the stringent BACT limits for normal operations during the commissioning period, for a number of reasons. First, the SCR systems and oxidation catalysts cannot be installed immediately when the turbines are initially started up. There may be debris in the equipment from the manufacture and installation of the equipment, which would damage the catalysts if they were installed immediately. Instead, the turbines need to be operated without the SCR systems and oxidation catalysts for a period of time to protect the equipment from physical or chemical damage. In addition, once all of the pollution control equipment is installed, it needs to be tuned in order to achieve optimum emissions performance. Until the equipment is tuned, it will not be able to achieve the very high levels of emissions reductions reflected in the stringent BACT limits for normal operations.

Because the BACT limits established for normal operations are not technically feasible during the commissioning period, these limits are not BACT for this phase of the facility's operation. Alternate BACT limits must therefore be specified for this mode of operation. To do so, the District has conducted an additional BACT analysis specifically for the required commissioning activities.

The only control technology available for limiting emissions during commissioning is to use best work practices to minimize emissions as much as possible during commissioning, and to expedite the commissioning process so that compliance with the stringent BACT limits for normal operations can be achieved as quickly as possible. There are no add-on control devices or other technologies that can be installed for commissioning activities.

To implement best work practices as an enforceable BACT requirement, the District is proposing conditions that will require the simple-cycle gas turbines to minimize emissions to the maximum extent possible during commissioning. The District is also proposing numerical emissions limits based upon the equipment manufacturer's best estimates of uncontrolled emissions at the operating loads that the simple-cycle gas turbines will experience during commissioning (See **Table 19** for Commissioning Estimates).[61] The proposed permit conditions will limit emissions to below the following levels:

TABLE 18. COMMISSIONING PERIOD EMISSIONS LIMITS FOR ONE SIMPLE-CYCLE GAS TURBINE

Air Pollutant	Proposed Commissioning Period Emissions Limits for One Simple-Cycle Gas Turbine	
NO_2	408 lb/day	51 lb/hr
Carbon Monoxide	360 lb/day	45 lb/hr
POC	35.8 lb/day	
PM_{10}	20.0 lb/day	
SO_2	7.3 lb/day	

All emissions from commissioning activities will be counted towards the facility's annual limits. Because commissioning is a relatively short-term period, the facility should be able to stay within those annual emission limits over the course of the first year of operation. Counting commissioning emissions towards the annual limits will also provide an additional incentive for the facility operator to minimize emissions as much as possible.

The District is also proposing permit conditions to minimize the duration of commissioning activities. The proposed conditions require the facility to tune the combustion turbine to minimize emissions at the earliest feasible opportunity; and to install, adjust and operate the SCR systems and oxidation catalysts at the earliest feasible opportunity. The District is also proposing to cap the total amount of time that each turbine can operate partially abated and/or without the SCR systems and oxidation catalysts at 200 hours. This limit represents the shortest amount of time in which the facility can reasonably complete the required commissioning activities without jeopardizing safety and equipment warranties. The proposed 200-hour limit is based on the following GE estimates for each specific commissioning activity (**Table 19**).

[61] Mariposa Energy to BAAQMD. January 27, 2010. See Attachment Table 5.1B.1R

TABLE 19. COMMISSIONING SCHEDULE FOR A SINGLE SIMPLE-CYCLE GAS TURBINE

Activity	Total Hours (hours)	Load Range (%)	Total Emissions		
			NO_x (lb)	CO (lb)	VOC (lb)
Initial Load Testing and Engine Checkout	8	≤10%	408	360	35.8
Pre-Catalyst Initial Tuning	72	50-100%	3,672	3,240	323
Post-Catalyst Tuning	120	50-100%	4,080	744	144
Total	200		8,160	4,344	503

Notes:
Initial Load Testing and Engine Checkout include unsynchronized operation followed by low load engine check.
Pre-catalyst and post catalyst tuning include the periods both before and after SCR and CO catalyst loading. Post catalyst period includes water injection for NOx and CO catalyst use.
SOX and PM10 emission during commissioning will not be higher than normal operation

Compliance with these proposed conditions for the commissioning period will be monitored by Continuous Emissions Monitors that the applicant will be required to install before any commissioning work begins, and through a written commissioning plan laying out all commissioning activities in advance, which the applicant will be required to submit to the District for review and approval.

6. Requirement to Offset Emissions Increases

District regulations require that new facilities must provide Emission Reduction Credits (ERCs) to offset the increases in air emissions that they will cause. ERCs are generated when old facilities sources are shut down, or when sources are controlled below regulatory limits. The emissions reductions granted by the District are used to offset the increases from new facilities, so that there will be no overall increase in emissions from facilities subject to this offset program.

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NOx emission increases from permitted sources at facilities which will emit 10 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NOx offsets must be provided by the Applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NOx.

The applicable offset ratios and the quantity of offsets required are summarized in **Table 20**.

6.1 POC Offsets

Because the proposed Mariposa Energy Project will emit less than 35 tons of POC per year from permitted sources, the POC emissions must be offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302. The facility will be required to provide offsets for 10.3 tons per year of POC emissions. The Applicant has purchased ERCs to offset this level of POC emissions.

6.2 NO_x Offsets

Because the proposed Mariposa Energy Project will emit greater than 35 tons per year of NOx) from permitted sources, the NOx emissions must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. The facility will emit up to 45.6 tons/yr of NOx, and will therefore be required to provide offsets for 52.44 tons per year of NOx emissions. The Applicant has purchased ERCs to offset this level of NOx emissions.

6.3 PM_{10} Offsets

Because the total PM10 emissions from permitted sources will not exceed 100 tons per year, the proposed Mariposa Energy Project is not required to offset its PM10 emissions under District Regulation 2-2-303.

6.4 SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the SO_2 emission increases associated with this project since the facility's SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 allows for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The Applicant has opted not to provide such emission offsets.

6.5 Offset Package

Table 20 summarizes the offset obligation of the proposed Mariposa Energy Project. The emission reduction credits presented in Table 21 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as banking certificates by the District under the certificates cited in the tables below. If the quantity of offsets issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated below, Mariposa Energy LLC (Mariposa) is in possession of valid emission reduction credits to offset the emission increases from the permitted sources for the Mariposa Energy Project.

TABLE 20. EMISSION REDUCTION CREDITS IDENTIFIED BY MARIPOSA (TON/YR)

	POC	NO_x
Valid Emission Reduction Credits[a]	11.1	55.9
Permitted Source Emission Limits	10.3	45.6
Offsets Required	10.3[b]	52.4[c]

[a]From Banking Certificates 1182 and 1184 (See Table below)
[b]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302
[c]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302

TABLE 21. CERTIFICATES HELD BY MARIPOSA (TON/YR)

Certificate	1182	1184	Total
NO_x	55.9	0.0	55.9
POC	0.0	11.1	11.1

TABLE 22. LOCATION OF CERTIFICATES HELD BY MARIPOSA

Current Certificate	Original Certificate	Company	Location	Original Issue Dates
#1182	1142	Owens Corning	Santa Clara	2/2009
#1184	1140	Quebecor	San Jose	2/2009

Note: The numbers of each certificate change with each transaction in the emissions bank. Certificate numbers below are the original certificate number when the emission reduction was generated.
Certificate 1142 was generated from the modification of process equipment.
Certificate 1140 was generated from the shutdown of the Quebecor printing facility.

7. Federal Permit Requirements

In addition to the Bay Area Air Quality Management District permit requirements in District Regulation 2, Rule 2 and Regulation 2, Rule 3, there are two federal permitting programs that apply to major facilities: (i) the federal "Prevention of Significant Deterioration" (PSD) requirements under 40 C.F.R. section 52.21; and (ii) the "Non-Attainment New Source Review" (Non-Attainment NSR) requirements for PM2.5 sources set forth in Appendix S of 40 C.F.R. Part 51. The District has analyzed these requirements for the proposed Mariposa Energy Project and has determined that neither of these permit requirements applies to this facility because it will not be a major source under either of those programs. The District is therefore not proposing to issue a PSD permit for this facility or to include Appendix S PM2.5 Non-Attainment NSR requirements in the permit.

7.1 Federal "Prevention of Significant Deterioration" Program

7.1.1 Applicability of the "Prevention of Significant Deterioration" Requirements

The federal PSD program applies to "major" stationary sources, which are defined as new sources that emit more than 250 tons per year of any PSD pollutant.[62] PSD pollutants are regulated pollutants for which the Bay Area is not in violation of the National Ambient Air Quality Standard (NAAQS) for that pollutant. For the Bay Area, PSD pollutants include carbon monoxide, PM10, and SO2, among others. Facilities that exceed the federal PSD "major source" threshold for any of these pollutants must apply for and obtain PSD permits before they can commence construction. Although PSD permits are federal permits issued under the authority of EPA Region 9, the District conducts the PSD analysis and issues PSD permits on behalf of EPA Region 9 pursuant to a Delegation Agreement between the District and EPA Region 9.[63]

The proposed Mariposa Energy Project will not emit more than 250 tons per year of any PSD pollutant, and will not be a "major source" subject to federal PSD requirements. Therefore, the Air District is not proposing to issue a federal PSD permit for this facility.

7.1.2 Protection of National Ambient Air Quality Standards

Although the District has concluded that the Mariposa Energy Project is not subject to PSD requirements because it is not a "major" source as defined in the PSD regulations, the District has nevertheless conducted a review of the air quality modeling materials provided by the Applicant as part of their CEC Application for Certification (AFC). The Applicant's analysis used sophisticated EPA-approved air pollution models to evaluate the ambient air impacts from air pollutant emissions from the proposed facility and found that the emissions from the proposed facility would

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[62] See 40 C.F.R. § 52.21(b)(1)(i)(b). Note that for 28 specific types of sources, a lower PSD applicability threshold of 100 tons applies pursuant to 40 C.F.R. § 52.21(b)(1)(i)(a). Simple-cycle combustion turbines of the type proposed for the Mariposa Energy Project are not in any of the categories subject to the 100 ton threshold specified in Section 52.21(b)(1)(i)(a).

[63] The District also has incorporated PSD requirements from the federal PSD regulations into its NSR Rule in Regulation 2, Rule 2. The substance of these requirements in Regulation 2, Rule 2 track the federal requirements.

not cause or contribute to air pollution in violation of any applicable National Ambient Air Quality Standards.

Per Rule 2, Regulation 2-2-417, a project is required to conduct a visibility, soils, and vegetation analysis if the proposed project is subject to PSD requirements and is within 10 kilometers of a Class I area. As previously stated, Mariposa Energy Project is not subject to PSD requirements and the proposed project site is greater than 10 kilometers from the nearest Class I area (i.e., the Point Reyes National Seashore). Therefore, a visibility, soils, and vegetation assessment was not required as part of the analysis.[64].

7.2 Non-Attainment NSR for $PM_{2.5}$

The Bay Area has recently been designated as "non-attainment" of the National Ambient Air Quality Standard for PM2.5 (24-hour average).[65] Areas classified as non-attainment are subject to the "Non-Attainment New Source Review" (Non-Attainment NSR) requirements of the federal Clean Air Act. The Clean Air Act requires states to develop Non-Attainment NSR regulations to implement this requirement within 3 years of a non-attainment designation, and the District will be doing so for PM2.5 in the months and years to come. In the interim, while the District is working on its own PM2.5 Non-Attainment NSR regulations, Non-Attainment NSR for PM2.5 is governed by the federal Non-Attainment NSR rule in EPA's Clean Air Implementation Rule, which is set forth in Appendix S of 40 C.F.R. Part 51 ("Appendix S").

Non-Attainment NSR under Appendix S is a federal permit program and is implemented under the federal regulations set forth in Appendix S. It is not a state law permitting program and it is not implemented under the requirements of District regulations established pursuant to the California Health & Safety Code. The Environmental Protection Agency has determined that the District can impose conditions in its District permits (Authority to Construct and Permit to Operate) that will allow a facility to establish compliance with the federal Non-Attainment NSR requirements for PM2.5.[66],[67] If the District includes requirements in its District permits pursuant to District Regulation 2-1-403 (Permit Conditions) that satisfy the applicable PM2.5 Non-Attainment NSR

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[64] However, the Applicant's AFC does provide a screening level analysis of potential visibility, soils, and vegetation impacts and concluded the project impacts would be less than significant.

[65] EPA promulgated National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ in 1997 (with an update in 2006), and began designating certain regions of the country as non-attainment with those Standards starting in 2005. EPA made a determination as to the region's attainment status with respect to $PM_{2.5}$, which it published on November 13, 2009. EPA determined that the Bay Area is in attainment of the $PM_{2.5}$ NAAQS for the annual standard, and is non-attainment for the 24-hour standard. The EPA's non-attainment determination for the $PM_{2.5}$ 24-hour standard became effective on December 14, 2009 (See Federal Register Friday November 13, 2009, Air Quality Designations for the 2006 24-Hour Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards).

[66] Letter dated 10/28/09 from Jack Broadbent of BAAQMD to Deborah Jordan U.S. EPA Region IX, Re: Guidance on "Appendix S" Non-Attainment NSR Permitting for $PM_{2.5}$ Source during PM2.5 Transition Period.

[67] Letter dated 12/9/09 from Deborah Jordan U.S. EPA Region IX to Jack Broadbent of BAAQMD, Re: Guidance on "Appendix S" Non-Attainment NSR Permitting for $PM_{2.5}$ Source during $PM_{2.5}$ Transition Period.

requirements of Appendix S for a source, EPA has determined that it will treat those conditions as satisfying the federal Appendix S requirements for that source.

Under Appendix S, Non-Attainment NSR requirements for PM2.5 apply to facilities with PM2.5 emissions of more than 100 tons per year. (See 40 CFR 51, Appendix S, II.A.4(i)(a) (establishing 100 tpy threshold for regulation of Major Stationary Sources).[68]) The proposed Mariposa Energy Project would emit less than 100 tons per year of PM2.5, so the Appendix S Non-Attainment NSR requirements do not apply for this facility. The District is therefore not proposing to include conditions in the permit for compliance with Appendix S for PM2.5.

[68] The facility will emit less than 100 tons per year of direct $PM_{2.5}$ emissions and less than 100 tons per year of any $PM_{2.5}$ precursors, as defined in Appendix S II.A.31(iii). (*See* Table 5).

8. Health Risk Screening Analyses

Pursuant to the BAAQMD Risk Management Regulation 2, Rule 5, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed Mariposa Energy Project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the Mariposa Energy Project are summarized in Table 6 in Section 4.2. **Table 23** presents the Health Risk Assessment Results for the Mariposa Energy Project. In accordance with the requirements of District Regulation 2, Rule 5 and California Office of Health Hazard Assessment (OEHHA) guidelines, the impact on public health due to the emission of these compounds was assessed utilizing EPA-approved air pollutant dispersion models.

TABLE 23. HEALTH RISK ASSESSMENT RESULTS

Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index	Acute Non-Cancer Hazard Index
Maximum Values	TBD by BAAQMD	TBD by BAAQMD	TBD by BAAQMD

The health risk assessment performed by the Applicant has been reviewed and verified by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to BAAQMD Regulation 2, Rule 5, the increased carcinogenic risk attributed to this project will not be significant since it is less than 1.0 in one million. The chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants is each less than significant since each is less than 1.0. Therefore, the proposed Mariposa Energy Project will be in compliance with District Regulation 2, Rule 5. Please see Appendix TBD (Memo dated TBD prepared by Jane Lundquist, Air Toxics Section) for further discussion.

9. Other Applicable Requirements

The following section summarizes the applicable District, state and federal rules and regulations and describes how the Mariposa Energy Project will comply with those requirements.

9.1 Applicable District Rules and Regulations

9.1.1 Regulation 1, Section 301: Public Nuisance

None of the project's sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District.

9.1.2 Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Sections 2-1-301 and 2-1-302, the Applicant has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for all regulated sources at the proposed Mariposa Energy Project. Those permits will be issued after the CEC completes its licensing process.

9.1.3 Regulation 2, Rule 2: New Source Review

The primary requirements of New Source Review that apply to the proposed Mariposa Energy Project are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2- 302; "Offset Requirements, precursor organic compounds and Nitrogen Oxides, NSR", Section 2-2-303, "Offset Requirement, PM10 and sulfur dioxide, NSR".

Regulation 2, Rule 2, Section 301: BACT

The District has performed a BACT analysis for NOx, CO, POC, PM10 and SOx as shown in Section 5. The proposed Mariposa Energy Project meets the BACT requirements under Section 2-2-301.

Regulation 2, Rule 2: Sections 302 and 303

The District has presented the offsets for the project for NOx, POC, and PM10 as shown in Section 6. The proposed Mariposa Energy Project meets the offset requirements under Sections 2-2-302 and 2-2-303.

Regulation 2, Rule 2: Sections 304, 305, 306 and 414

The Prevention of Significant Deterioration (PSD) requirements in District Regulation 2, Rule 2 (Sections 304, 305, 306, and 308) are intended to implement the federal PSD requirements in 40 C.F.R. Section 52.21 and track those federal requirements. The proposed Mariposa Energy Project will not be subject to PSD requirements. Those requirements are discussed in detail in Section 7 above.

9.1.4 Regulation 2, Rule 3: Power Plants

Pursuant to Section 2-3-304, this Preliminary Determination of Compliance is subject to the public notice, public comment, and public inspection requirements contained in Sections 2-2-406 and 407. This document presents the Preliminary Determination of Compliance for the project. The District will consider all comments received during the comment period prior to issuing any Final Determination of Compliance for the project. The Final Determination of Compliance will be relied upon by the CEC in their licensing amendment proceeding. If the CEC grants a license to the project, then the District will issue an Authority to Construct.

9.1.5 Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants

A risk screening analysis was performed to estimate the health risk resulting from the toxic air contaminant (TAC) emissions from the proposed Mariposa Energy Project. Results from this analysis indicate that the maximally exposed individual cancer risk is estimated at TBD in a million, the chronic non-cancer hazard index at TBD in a million, and acute non-cancer hazard index at TBD in million. Therefore the proposed Mariposa Energy Project will be in compliance the requirements of Section 2-5-301. Furthermore, the emission controls (abatement by an oxidation catalyst) are toxic best available control technology (TBACT).

9.1.6 Regulation 2, Rule 6: Major Facility Review

Pursuant to Section 404.1, the owner/operator of the Mariposa Energy Project shall submit an application to the District for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Sections 2-6-212.1 and 2-6-218, the Mariposa Energy Project will become subject to Regulation 2, Rule 6, upon completion of construction as demonstrated by first firing of the gas turbines.

9.1.7 Regulation 2, Rule 7: Acid Rain

The Mariposa Energy Project gas turbine units will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72.

40 CFR Part 72, Subpart A - Acid Rain Program

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The gas turbines are affected units subject to the program in accordance with 40 CFR Part 72, Subpart A, Section 72.6(a).

40 CFR Part 72, Subpart C – Acid Rain Permit Applications

Part 72, Subpart C, requires that the Applicant submit a complete Acid Rain Permit application 24 months prior to first firing of the gas turbines.

40 CFR Part 73 – Sulfur Dioxide Allowance System

Part 73 establishes the sulfur dioxide allowance system for tracking, holding, and transferring allowances. Prior to operation of the gas turbines the Applicant will be required to obtain adequate SO_2 allowances.

40 CFR Part 75 – Continuous Emission Monitoring

Part 75 contains the continuous emission monitoring requirements for units subject to the Acid Rain program. The Applicant will be required to meet the Part 75 requirements for monitoring, recordkeeping and reporting of SO_2, NOx, and CO_2 emissions. The Applicant will also need to meet Part 75 requirement for monitoring, recordkeeping, and reporting volumetric flow rate and opacity.

9.1.8 Regulation 6, Rule 1: Particulate Matter – General Requirements

The combustion of natural gas at the gas turbines is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Section 310, the grain loading resulting from the operation of each gas turbine is 0.0012 gr/dscf @ 15% O_2 (0.0042 gr/dscf @ 0% O_2). See Appendix TBD for simple-cycle gas turbine grain loading calculations.

The 220 hp diesel fire pump driver for the Mariposa Energy Project will meet the Tier III emission certification standards and the diesel air toxics control measure requirements. Therefore, the particulate emissions from the fire pump driver are expected to comply with Section 301, 302, and 310.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements, but are subject to Regulation 6, Rule 1. However, the California Energy Commission will impose requirements for construction activities such as the use of water and/or chemical dust suppressants to minimize PM10 emissions and prevent visible particulate emissions.

9.1.9 Regulation 7: Odorous Substances

Section 302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Section 303 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from the simple-cycle units will be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

9.1.10 Regulation 8: Organic Compounds

The gas turbines are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" Section 110 since natural gas will be fired exclusively at those sources.

The use of solvents for cleaning and maintenance at the Mariposa Energy Project is expected to be at a level that is exempt from permitting in accordance with Regulation 2, Rule 1, Section 118. The facility may utilize less than 20 gallons per year of solvent for wipe cleaning per Section 118.9 and remain exempt from permitting requirements. The facility may also utilize a cold cleaner for maintenance cleaning as long as the unit meets the exemption set forth in Section 118.4. The facility may also perform solvent cleaning and preparation using aerosol cans meeting the exemption set forth in Section 118.10. Any solvent usage exceeding the amounts in Section 118 would require a permit. In addition, any solvent usage in excess of a toxic air contaminant trigger level contained in Regulation 2, Rule 5 would require a permit.

9.1.11 Regulation 9: Inorganic Gaseous Pollutants

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppmv (dry).

With maximum projected SO_2 emissions less than 1 ppmv, the gas turbines are not expected to exceed the limits specified in Section 301 and should easily comply with Section 302. The results of the dispersion modeling for the Mariposa Energy Project included in the CEC AFC also concludes that off-property SO_2 ground level concentrations will be below the 0.5 ppm level for 3 consecutive minutes, 0.25 ppm level averaged over 60 consecutive minutes, and the 0.05 ppm level averaged over 24 hours. Therefore, the off-property ground level concentrations from the operation of the gas turbines and the diesel fire pump driver are not expected to exceed the limits specified in Section 301 and should easily comply with Section 302.

Section 304 prohibits the burning of liquid fuels having a sulfur content in excess of 0.5% by weight. The diesel fire pump driver will burn diesel fuel with less than 15 ppm sulfur. Therefore, the sulfur content in the fuel will be less than 0.5% and will comply with Section 304.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

This regulation establishes nitrogen oxides and carbon monoxide emission limits from stationary internal combustion engines with an output rated by the manufacturer at more than 50 brake horsepower. Therefore, the simple-cycle gas turbines are not subject to Regulation 9, Rule 8 requirements.

The Mariposa Energy Project will include a 220 brake horsepower diesel fire pump driver. The engine will be operated 20 minutes per month for maintenance and testing or 4 hours per year, which is less than the limited exemption for low usage threshold in Regulation 9, Rule 8, Section 9-8-111. Therefore the diesel fire pump driver will be exempt from the Regulation 9, Rule 8 requirements. However, in order to maintain the exemption, Mariposa will be required to meet the reporting requirements specified in Regulation 9, Rule 8, Section 9-8-502.1 and 9-8-530.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the combustion gas turbines will be limited by permit condition to NOx emissions of 2.5 ppmvd @ 15% O_2, respectively, they will comply with the NOx limitation in Section 301.2 of 5 ppmvd @ 15% O_2 or 0.15 lb/MW-hr.

9.2 Regulation 10: Standards of Performance for New Stationary Sources

Generally Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. However, the District has not sought delegation of the New Source Performance Standard (NSPS) contained in Subpart KKKK. Subpart KKKK "Standards of Performance for Stationary Gas Turbines" applies to this facility. The gas turbines will comply with all applicable standards and limits required by these regulations. The applicable emission limitations are summarized below:

TABLE 24. NEW SOURCE PERFORMANCE STANDARDS FOR SIMPLE-CYCLE GAS TURBINES

Source	Requirement	Emission Limitation	Compliance Demonstration
Gas Turbines	Subpart KKKK	0.43 lb NO_x/MW-hr, or 15 ppm NO_x as NO_2 @ 15%O_2, 0.9 lb SO_2/MW-hr, or 0.06 lb SO_2/MMBtu maximum No CO limit in Subpart KKKK No PM limit in Subpart KKKK	2.5 ppm NO_x as NO_2 @ 15%O_2 Permit Limit; 0.0028 lb/MMBtu of SO_2 Permit Limit

9.2.1 40 CFR Part 60 Subpart KKKK

Section 60.4375 requires submittal of reports of excess emissions and monitoring of downtime for all periods of unit operation, including startup, shutdown, and malfunction. The Applicant is expected to maintain adequate records for Subpart KKKK reporting requirements. The gas turbines will be equipped with continuous emissions monitors for NOx. An annual NOx emission test will not be required for Subpart KKKK as long as a compliant CEM is used to monitor emissions.

No sulfur content monitoring of the natural gas is required by Subpart KKKK if the facility demonstrates the fuel meets the sulfur content requirements contained in Section 60.4365 using the information required by Section 60.4365(a).

9.2.2 40 CFR Part 60 Subpart IIII

40 CFR Part 60 Subpart IIII establishes the standards of performance for stationary compression ignition internal combustion engines. Therefore, the diesel fire pump driver for the Mariposa Energy Project would be subject to the emission limits of Subpart IIII. The NMHC+NOx emission limit for a model year 2009 fire pump driver between 175 and 300 hp would be 3.0 g/bhp, the CO emission limit would be 2.6g/bhp, and the PM10 emission limit would be 0.15 g/bhp.

The proposed diesel fire pump driver would be a Tier III, 220 bhp internal combustion engine. Therefore, the engine would meet the NMHC+NOx, CO, and PM10 emission standards.

9.2.3 40 CFR Part 63 Subpart YYYY

Subpart YYYY contains the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Combustion Turbines. This regulation has been stayed (Federal Register; April 7, 2004, Volume 69, Number 67) for a combustion turbine that is a lean premix gas fired unit or a diffusion flame gas fired unit.

The emissions standards contained in Subpart YYYY have been stayed for natural gas fired combustion turbines. If a gas fired combustion turbine was subject to Subpart YYYY, then it would still need to comply with the Initial Notification requirements in Section 63.6145.

Subpart YYYY does not apply to the Mariposa Energy Project gas turbines since the facility is not a major source of Hazardous Air Pollutants (HAPs). The Mariposa Energy Project emits less than the major HAP thresholds of 10 tons/year of any single HAP, or 25 tons/year of aggregate HAP. Please note that ammonia is not considered a HAP.

9.2.4 40 CFR Part 64 (CAM Rule)

40 CFR Part 64 establishes onsite monitoring requirements for emission control systems. The CAM rule applies to emission units with uncontrolled potential to emit levels greater than applicable major source thresholds. The uncontrolled potential to emit levels for the Mariposa Energy Project would be below the major source thresholds based on the uncontrolled turbine emission rates and an upper limit of 4,000 hours of operation per year. Therefore, the provisions of the CAM rule are not applicable to the Mariposa Energy Project.

9.3 State Requirements

The proposed Mariposa Energy Project will be subject to the Air Toxic "Hot Spots" Program contained in the California Health and Safety Code Section 44300 et seq. The facility will be required to prepare inventory plans and reports as required.

The proposed diesel fire pump driver for the Mariposa Energy Project will be subject to the diesel air toxics control measure (diesel ATCM) contained in the California Health and Safety Code Section 93115. The purpose of the ATCM is to limit emissions, particularly diesel particulate emissions, from stationary diesel fired compression engines. The proposed fire pump driver would meet the Tier III emission standards and non-emergency hours would be limited to four hours or less per year. Therefore, the Mariposa Energy Project would comply with the diesel ATCM.

9.4 Greenhouse Gases

Climate change poses a significant risk to the Bay Area with such impacts such as rising sea levels, reduced runoff from snow pack in the Sierra Nevada, increased air pollution, impacts to agriculture, increased energy consumption, and adverse changes to sensitive ecosystems. The generation of electricity from burning natural gas produces air emissions known as greenhouse gases (GHGs) in addition to the criteria air pollutants. GHGs are known to contribute to the warming of the earth's atmosphere. These include primarily carbon dioxide, nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (unburned natural gas). Also included are sulfur hexafluoride (SF6) from transformers, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chillers.

The California Global Warming Solutions Act of 2006 (AB32) requires the California Air Resources Board (ARB) to adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990 to be achieved by 2020. To achieve this, ARB has a mandate to adopt rules and regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The ARB is expected to adopt early action GHG reduction measures in the near future to reduce greenhouse gas emissions by 2020. ARB has adopted regulations requiring mandatory GHG emissions reporting. The facility is expected to report all GHG emissions to meet ARB requirements.

The facility will also be required to report GHG emissions to CARB, the District, and US EPA. In 2008, the District placed a fee on GHG emissions from large stationary sources of GHGs.

The GHG emissions estimates for Mariposa Energy Project are shown below.

TABLE 25. MARIPOSA ENERGY PROJECT GHG EMISSIONS

Gas Turbines							
GHG	**Fuel Usage MMBtu/year**	**Emission Factor (kg CO_2/MMBtu)**	**Emission Factor (g CH_4/MMBtu)**	**Emission Factor (g N_2O/MMBtu)**	**GHG (metric tons/year)**	**Global Warming Potential**	**CO2 equivalents (metric tons/year)**
CO_2	8,133,970	53.06			431,588	1	431,588
CH_4	8,133,970		0.0059		48	21	1008
N_2O	8,133,970			0.001	0.8	310	248
Diesel Fire Pump							
GHG	**Fuel Usage gallons/year**	**Emission Factor (kg CO_2/gal)**	**Emission Factor (kg CH_4/gal)**	**Emission Factor (kg N_2O/gal)**	**GHG (metric tons/year)**	**Global Warming Potential**	**CO_2 equivalents (metric tons/year)**
CO_2	45.2	10.15			0.46	1	0.46
CH_4	45.2		0.0003		1.4E-05	21	2.9E-04
N_2O	45.2			0.0001	4.5E-06	310	1.4E-03
Total							**432,844**

Gas turbine GHG emission factors from the California Climate Action Registry (CCAR), General Reporting Protocol, Version 3.0, April 2008
CO2 Emission Factor from Table C.6
CH4 and N2 O Emission Factors from Table C.7
Diesel fire pump driver GHG Emission Factors from the CCAR, General Reporting Protocol, Version 3.0, April 2008
CO2 Emission Factor from Table C.6 (distillate oil)
CH4 and N2 O Emission Factors from Table C.7 (distillate oil)

Mariposa Energy Project has the potential to emit 432,844 metric tons/year of CO_2 equivalents using the California Climate Action Registry (CCAR) General Reporting Protocol calculation methodology.

The Mariposa Energy Project simple-cycle gas turbines will have a gross thermal efficiency of 40% (HHV).[69] The Mariposa Energy Project simple-cycle gas turbines will have a heat rate of 8,591 (LHV) Btu/KW-hr at 59ºF and a relative humidity of 60% (See Appendix TBD).

The EPA Administrator has recently stated that by April of 2010, the Administrator will take actions to ensure that no stationary sources will be required to get a Clean Air Act permit to cover GHG emissions in calendar year 2010.[70] In addition, in the first half of 2011, only sources required by non-GHG emissions to obtain a permit under the Clean Air Act will need to address their GHG emission in their permit applications. Therefore, the Mariposa Energy Project is not required to address GHG emissions under the Clean Air Act at this time.

As the lead agency under the CEQA-equivalent process, the CEC will be required to quantify and assess GHG emissions from the Mariposa Energy Project to evaluate the facility's compliance with applicable laws, ordinances, regulations and standards, and the potential impacts and benefits associated with adding the Mariposa Energy Project to the electricity system.

9.5 Environmental Justice

The District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The District has worked to fulfill this commitment in the current permitting action.

The emissions from the proposed project will not cause or contribute to any significant public health impacts in the community. As described in detail above, the District has undertaken a detailed review of the potential public health impacts of the emissions authorized under the proposed permitting action, and has found that they will involve no significant public health risks. The District has found that the maximum lifetime cancer risk associated with the facility is 0.77 in one million, and that the maximum chronic Hazard Index would be 0.0008 and the maximum acute Hazard Index would be 0.070. These risk levels are far below what the District, EPA, or any other public health agency would consider to be significant. The District anticipates that there will be no significant impacts due to air emissions related to the Mariposa Energy Project after all of the mitigations required by District Rules and the California Energy Commission are implemented. The District does not anticipate an adverse impact on any community due to air emissions from the Mariposa Energy Project and therefore there is no disparate adverse impact on any Environmental Justice community located near the facility.

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[69] See AFC Section 2.4.3.

[70] Letter dated February 22, 2010 from Lisa Jackson to Senator Rockefeller, Letter summarizes EPA proposals on regulating green house gases.

10.Proposed Permit Conditions

The District is proposing the following permit conditions to ensure that the project complies with all applicable District, state, and federal Regulations. The proposed conditions would limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. The permit conditions specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb/hr and lb/MMBtu of natural gas fired) will insure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations are being proposed on the type or quantity of gas turbine start-ups or shutdowns. Instead, the facility would be required to comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NOx limitations would be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up, shutdown, combustor tuning, and transient conditions. Compliance with POC, SO_2, and PM10 mass emission limits would be verified by annual source testing.

In addition to permit conditions that apply to steady-state operation of each gas turbine power train, the District is proposing conditions that govern equipment operation during the initial commissioning period when the gas turbine power trains will operate without their SCR systems and/or oxidation catalysts in place. Commissioning activities include, but are not limited to, the testing of the gas turbines, and adjustment of control systems. Parts 1 through 10 of the proposed permit conditions for the simple-cycle gas turbines apply to this commissioning period and are intended to minimize emissions during the commissioning period.

10.1 Proposed Mariposa Energy Project Permit Conditions

Definitions:

Hour	Any continuous 60-minute period
Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
Year:	Any consecutive twelve-month period of time
Rolling 3-hour period:	Any consecutive three-clock hour period, not including start-up or shutdown periods
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MMBtu:	million British thermal units
Gas Turbine Start-up Mode:	The lesser of the first 30 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 17(b) and 17(d).
Gas Turbine Shutdown Mode:	The lesser of the 15 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 17(b) and 17(d) until termination of fuel flow to the Gas Turbine
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (exhaust of S-1 Gas Turbine), P-2 (exhaust of S-2 Gas Turbine) P-3 (exhaust of S-3 Gas Turbine), P-4 (exhaust of S-4 Gas Turbine), the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the MEP construction contractor to insure safe and reliable steady-state operation of the gas turbines, heat recovery steam generators,

	steam turbine, and associated electrical delivery systems during the commissioning period
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
MEP:	Mariposa Energy Project
Total Particulate Matter	The sum of all filterable and all condensable particulate matter.

10.2 LM6000 PC Sprint Simple-Cycle Gas Turbines

<u>Applicability:</u>

Parts 1 through 10 of this condition shall only apply during the commissioning period as defined above. Unless otherwise indicated, Parts 11 through 42 of this condition shall apply after the commissioning period has ended.

<u>Conditions for the Commissioning Period for the GE LM6000 PC Sprint Gas Turbines</u>

1. The owner/operator shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-2, S-3 and S-4 Gas Turbines to the maximum extent possible during the commissioning period. (Basis: BACT, Regulation 2, Rule 2, Section 409)

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1, S-2, S-3 and S-4 Gas Turbines combustors to minimize the emissions of carbon monoxide and nitrogen oxides. (Basis: BACT, Regulation 2, Rule 2, Section 409)

3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall install, adjust, and operate the A-1, A-3, A-5 and A-7 Oxidation Catalysts and A-2, A-4, A-6 and A-8 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-2, S-3, and S-4 Gas Turbines. (Basis: BACT, Regulation 2, Rule 2, Section 409)

4. The owner/operator shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1, S-2, S-3, and S-4 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to the initial load testing and checkout of the engine, the initial combustor tuning, the installation and

operation of the required emission control systems, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S2, S-3 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1, S-2, S-3 or S-4) sooner than 28 days after the District receives the commissioning plan. (Basis: Regulation 2, Rule 2, Section 419)

5. During the commissioning period, the owner/operator of the MEP shall demonstrate compliance with Parts 7, 8, 9, and 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters and emission concentrations:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1, S-2, S-3, and S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NOx and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request. (Basis: Regulation 2, Rule 2, Section 419)

6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in Part 5 prior to first firing of the Gas Turbines (S-1, S-2, S-3 and S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval. (Basis: Regulation 2, Rule 2, Section 419)

7. The owner/operator shall not fire S-1, S-2, S-3, or S-4 Gas Turbine without abatement of nitrogen oxide emissions by the corresponding SCR System A-2, A-4, A-6, or A-8 and/or abatement of carbon monoxide emissions by the corresponding Oxidation Catalyst A-1, A-3, A-5, or A-7 for more than 200 hours during the commissioning period. Such operation of any Gas Turbine (S-1, S-2, S-3, S-4) without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 200 firing hours without abatement shall expire. (Basis: BACT, Regulation 2, Rule 2, Section 409)

8. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-1, S-2, S-3, and S-4) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in Part 22. (Basis: Regulation 2, Rule 2, Section 409)

9. The owner/ operator shall not operate the Gas Turbines (S-1, S-2, S-3, and S-4) in a manner such that the pollutant emissions from each gas turbine will not exceed the following limits

during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1, S-2, S-3, S-4). (Basis: BACT, Regulation 2, Rule 2, Section 409)

NOx (as NO2)	408 pounds per calendar day	51 pounds per hour
CO	360 pounds per calendar day	45 pounds per hour
POC (as CH4)	35.8 pounds per calendar day	
PM10	20.0 pounds per calendar day	
SO2	7.3 pounds per calendar day	

10. Within 90 days after startup, the Owner/Operator shall conduct District and CEC approved source tests to determine compliance with the emission limitations specified in Part 17. The source tests shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Thirty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this Part. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of the source testing date. (Basis: Regulation 2, Rule 2, Section 419)

<u>Conditions for the GE LM6000 Simple-Cycle Gas Turbines (S-1, S-2, S-3, and S-4)</u>

11. The owner/operator shall fire the Gas Turbines (S-1, S-2, S-3, and S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1, S-2, S-3 and S-4 shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the facility. (Basis: BACT for SO2 and PM10)

12. The owner/operator shall not operate the units such that the heat input rate to each Gas Turbine (S-1, S-2, S-3, and S-4) exceeds 481 MMBtu (HHV) per hour. (Basis: BACT for NOx)

13. The owner/operator shall not operate the units such that the heat input rate to each Gas Turbine (S-1, S-2, S-3, and S-4) exceeds 11,551 MMBtu (HHV) per day. (Basis: Cumulative Increase for PM10)

14. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1, S-2, S-3, and S-4) exceeds 8,133,970 MMBtu (HHV) per year. (Basis: Offsets)

15. The owner operator shall not operate S-1, S-2, S-3, and S-4 such that the combined hours for all four units exceeds 16,900 hours per year (excluding operations necessary for maintenance, tuning, and testing). (Basis: Offsets, Cumulative Increase)

16. The owner/operator shall ensure that the each Gas Turbine (S-1, S-2, S-3, S-4) is abated by the properly operated and properly maintained Selective Catalytic Reduction (SCR) System A-2, A4, A-6 or A-8 and Oxidation Catalyst System A-1, A-3, A-5, or A-7 whenever fuel is combusted at those sources and the corresponding SCR catalyst bed (A-2, A-4, A-6 or A-8) has reached minimum operating temperature. (Basis: BACT for NOx, POC and CO)

17. The owner/operator shall ensure that the Gas Turbines (S-1, S-2, S-3, S-4) comply with requirements (a) through (j). Requirements (a) through (f) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (Basis: BACT and Regulation 2, Rule 5)

    a) Nitrogen oxide mass emissions (calculated as NO2) at each exhaust point P-1, P-2, P-3, and P-4 (exhaust point for S-1, S-2, S-3 and S-4 Gas Turbine after abatement by A-2, A4, A-6 and A-8 SCR System) shall not exceed 4.40 pounds per hour or 0.00915 lb/MMBtu (HHV) of natural gas fired. (Basis: BACT for NOx)
    b) The nitrogen oxide emission concentration at each exhaust point P-1, P-2, P-3 and P-4 shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O2, averaged over any 1-hour period. (Basis: BACT for NOx)
    c) Carbon monoxide mass emissions at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 2.14 pounds per hour or 0.00446 lb/MMBtu of natural gas fired, averaged over any 3-hour period. (Basis: BACT for CO)
    d) The carbon monoxide emission concentration at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O2 averaged over any 3-hour period. (Basis: BACT for CO)
    e) Ammonia (NH3) emission concentrations at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 5 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to each SCR System A-2, A-4, A-6, and A-8. The correlation between the gas turbine heat input rates, A-2, A-4, A-6, and A-8 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, P-3 and P-4 shall be determined in accordance with Part 27 or District approved alternative method. (Basis: Regulation 2, Rule 5)
    f) Precursor organic compound (POC) mass emissions (as CH4) at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 1.22 pounds per hour or 0.00255 lb/MMBtu of natural gas fired. (Basis: BACT for POC)
    g) Precursor organic compound (POC) mass emissions (as CH4) at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 2.0 ppm, on a dry basis, corrected to 15% O2 averaged over any 1–hour period. (Basis: BACT for POC)
    h) Sulfur dioxide (SO2) mass emissions at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 1.35 pounds per hour or 0.0028 lb/MMBtu of natural gas fired. (Basis: BACT for SO2)
    i) Particulate matter with an aerodynamic diameter equal to or less than 10 microns (PM10) mass emissions at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 2.5 pounds per hour. (Basis: BACT for PM10)
    j) Total particulate matter mass emissions at each exhaust point P-1, P-2, P-3, and P-4 shall not exceed 2.5 pounds per hour. (Basis: Regulation 2, Rule 2, Section 419)

18. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-2, S-3, and S-4) during a start-up or shutdown does not exceed the

limits established below. Startups shall not exceed 30 minutes. Shutdowns shall not exceed 15 minutes. (Basis: BACT Limit for Non-Normal Operation)

Pollutant	**Maximum Emissions Per Startup [a] (lb/startup)**	**Maximum Emissions Per Shutdown [b] (lb/shutdown)**	**Maximum Emissions During Hour Containing a Startup and Shutdown[c]**
NO_x (as NO_2)	14.2	3.2	18.5
CO	14.1	2.7	17.3
POC (as CH_4)	1.1	0.2	1.6

[a] Startups not to exceed 30 minutes.
[b] Shutdowns not to exceed 15 minutes.
[c] Worst case hourly emissions assume one startup and one shutdown in one hour.

19. The owner/operator shall not allow total combined emissions from the Gas Turbines (S-1, S-2, S-3, and S-4), including emissions generated during gas turbine start-ups, and shutdowns to exceed the following limits during any calendar day:

(a) 1,099 pounds of NOx (as NO2) per day (Basis: Cumulative Increase)
(b) 934 pounds of CO per day (Basis: Cumulative Increase)
(c) 134 pounds of POC (as CH4) per day (Basis: Cumulative Increase)
(d) 240 pounds of PM10 per day (Basis: Cumulative Increase)
(e) 87 pounds of SO2 per day (Basis: Cumulative Increase)

20. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines (S-1, S-2, S-3, and S-4), including emissions generated during gas turbine start-ups, shutdowns, and malfunctions to exceed the following limits during any consecutive twelve-month period:

(a) 45.6 tons of NOx (as NO2) per year (Basis: Offsets)
(b) 27.2 tons of CO per year (Basis: Cumulative Increase)
(c) 10.3 tons of POC (as CH4) per year (Basis: Offsets)
(d) 21.1 tons of PM10 per year (Basis: Cumulative Increase)
(e) 3.1 tons of SO2 per year (Basis: Cumulative Increase)

21. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per Part 26) from the Gas Turbines (S-1, S-2, S-3, S-4) combined to exceed the following limits:

formaldehyde 7,442 pounds per year
benzene 108 pounds per year
Specified polycyclic aromatic hydrocarbons (PAHs) TBD pounds per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. The owner/operator shall submit the risk analysis to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Basis: Regulation 2, Rule 5)

22. The owner/operator shall demonstrate compliance with Parts 12 through 15, 17(a) through 17(e), 18 (NOx, and CO limits), 19(a), 19(b), 20(a), and 20(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up and shutdown periods). The owner/operator shall monitor for all of the following parameters:

    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1, S-2, S-3, and S-4
    (b) Oxygen (O2) concentration, Nitrogen Oxides (NOx) concentration, and carbon monoxide (CO) concentration at exhaust points P-1, P-2, P-3 and P-4.
    (c) Ammonia injection rate at A-2, A-4, A-6 and A-8 SCR Systems

    The owner/operator shall record all of the above parameters at least every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

    The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

    (d) Heat Input Rate for each of the following sources: S-1, S-2, S-3, and S-4
    (e) Corrected NOx concentration, NOx mass emission rate (as NO2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1, P-2, P-3 and P-4.

    For each source, exhaust point, the owner/operator shall record the parameters specified in Parts 24(d) and 24(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

    (f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
    (g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and for S-1, S-2, S-3 and S-4 combined.
    (h) the average NOx mass emission rate (as NO2), CO mass emission rate, and corrected NOx and CO emission concentrations for every clock hour.
    (i) on an hourly basis, the cumulative total NOx mass emissions (as NO2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and for S-1, S-2, S-3 and S-4 combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NOx emission concentration, NOx mass emission rate (as NO2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine.

(k) on a monthly basis, the cumulative total NOx mass emissions (as NO2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for sources S-1, S-2, S-3, and S-4 combined.

(Basis: 1-520.1, 9-9-501, BACT, Offsets, NSPS, Cumulative Increase)

23. To demonstrate compliance with Parts 17(f), 17(g), 17(h), 17(i), 17(j), 19(c), 19(d), 19(e), 20(c), 20(d), 20(e), the owner/operator shall calculate and record on a daily basis, the precursor organic compound (POC) mass emissions, fine particulate matter (PM10) mass emissions (including condensable particulate matter), and sulfur dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual heat input rates measured pursuant to Part 24, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under Part 28 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

    (l) For each calendar day, POC, PM10, and SO2 emissions, summarized for each power train (Gas Turbine) and S-1, S-2, S-3, and S-4 combined

    (m) on a monthly basis, the cumulative total POC, PM10, and SO2 mass emissions, for each year for S-1, S-2, S-3, and S-4 combined.

    (Basis: Offsets, Cumulative Increase)

24. To demonstrate compliance with Part 23, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 8,133,970 MMBtu/year for S-1, S2, S-3, and S-4 combined and the highest emission factor (pounds of pollutant per MMBtu of heat input) determined by the most recent of any source test of the S-1, S-2, S-3, or S-4 Gas Turbines. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (Basis: Regulation 2, Rule 5)

25. Within 90 days of start-up of each of the MEP GE LM6000 PC-Sprint units, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, P-3, or P-4 to determine the corrected ammonia (NH3) emission concentration to determine compliance with Part 17(e). The source test shall determine the correlation between the heat input rates of the gas turbine, A-2, A-4, A-6, or A-8 SCR System ammonia injection rate, and the corresponding NH3 emission concentration at emission point P-1, P-2, P-3, or P-4. 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 NOx emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with Part 17(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia

injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Basis: Regulation 2, Rule 5)

26. Within 90 days of start-up of each of the GE LM6000 PC-Sprint units and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P1, P-2, P-3 and P-4 while each Gas Turbine is operating at maximum load to determine compliance with Parts 17(a), 17(b), 17(c), 17(d), 17(f), 17(g), 17(h), 17(i) and 17(j) and while each Gas Turbine is operating at minimum load to determine compliance with Parts 17(c), and 17(d) and to verify the accuracy of the continuous emission monitors required in Part 24. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and total particulate matter emissions including condensable particulate matter. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Basis: BACT, Offsets)

27. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to any measurement of the total particulate matter or PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Basis: BACT, Regulation 2, Rule 2, Section 419)

28. Within 90 days of start-up of each of the GE LM6000 PC-Sprint gas turbines and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on one of the following exhaust points P-1, P-2, P-3 or P-4 while the Gas Turbine is operating at maximum allowable operating rates to demonstrate compliance with Part 23. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to Part 26 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	3.8 pounds/year and 2.9 pounds/hour
Formaldehyde	≤	18 pounds/year and 0.12 pounds/hour
Specified PAHs	≤	TBD pounds/year

(Basis: Regulation 2, Rule 5)

29. The owner/operator shall calculate the sulfuric acid mist (SAM) emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to Part 32. If this SAM mass emission limit of Part 33 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist

emissions pursuant to Regulation 2, Rule 2, Section 306. (Basis: Regulation 2, Rule 2, Section 306)

30. Within 90 days of start-up of each of the GE LM6000 PC-Sprint gas turbines and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on two of the four exhaust points P-1, P-2, P-3 and P-4 while each gas turbine is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in Part 33. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Basis: Regulation 2, Rule 2, Section 306, and Regulation 2, Rule 2, Section 419)

31. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1, P-2, P-3, P-4 combined to exceed 7 tons in any consecutive 12 month period. (Basis: Regulation 2, Rule 2, Section 306, and Regulation 2, Rule 2, Section 419)

32. The owner/operator shall ensure that the stack height of emission points P-1, P-2, P-3 and P-4 is each at least 80 feet above grade level at the stack base. (Basis: Regulation 2, Rule 5)

33. The owner/operator shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Basis: Regulation 2, Rule 1, Section 403)

34. The owner/operator shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Basis: Regulation 2, Rule 1, Section 403, Regulation 2, Rule 6, Section 501)

35. The owner/operator shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Basis: Regulation 2, Rule 1, Section 403)

36. The Owner/Operator shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval, except that the facility shall provide four sampling ports that are at least 6 inches in diameter in the same plane of each gas turbine stack (P-1, P-2, P-3, P-4). (Basis: Regulation 1, Section 501)

37. Within 180 days of the issuance of the Authority to Construct, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by Parts 10, 27, 28, 30

and 32. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Basis: Regulation 1, Section 501)

38. The owner/operator shall ensure that the facility complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Basis: Regulation 2, Rule 7)

Conditions for the Diesel Fire Pump Driver (S-5)

39. The owner/operator shall fire S-5 Fire Pump Engine exclusively on diesel fuel having a sulfur content no greater than 0.05% by weight. The owner/operator shall obtain from the supplier and maintain records of the sulfur content certification for each lot of fuel. (Basis: TRMP, Cumulative Increase)

40. The owner/operator shall operate the S-5 Fire Pump Engine for no more than 4 hours per year for the purpose of reliability testing and non-emergency operation. (Basis: Cumulative Increase, Regulation 9-8-231 & 330)

41. The owner/operator shall equip the S-5 Fire Pump Engine with a non-resettable totalizing counter that records hours of operation. (Basis: cumulative increase)

42. The owner/operator shall maintain the following monthly records in a District-approved log for at least 5 years and shall make such records and logs available to the District upon request: (Basis: cumulative increase)

    a. Total number of hours of operation for S-5.
    b. Fuel usage at S-5

11.Preliminary Determination

The APCO has made a preliminary determination that the proposed Mariposa Energy Project, which is composed of the permitted sources listed below, complies with all applicable District, state and federal air quality rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S--1 Combustion Turbine Generator #1, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-1 Oxidation Catalyst, and A-2 Selective Catalytic Reduction System (SCR).

S-2 Combustion Turbine Generator #2, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-3 Oxidation Catalyst, and A-4 Selective Catalytic Reduction System (SCR).

S--3 Combustion Turbine Generator #3, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-5 Oxidation Catalyst, and A-6 Selective Catalytic Reduction System (SCR).

S-4 Combustion Turbine Generator #4, GE LM6000 PC Sprint, Natural Gas Fired, 50 MW (nominal), 481 MMBtu/hr (HHV) maximum rated capacity; abated by A-7 Oxidation Catalyst, and A-8 Selective Catalytic Reduction System (SCR).

S-5 Fire Water Pump Diesel Engine, Cummins 220 brake horsepower, Model CFP7E-F40 or equivalent Tier 3 compliant engine.

This document is subject to the public notice, public comment, and public inspection requirements of District Regulations 2-2-405 and 2-2-406. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Mariposa Energy Project and mailed to certain entities. The public inspection and comment period will be at least 30 days in duration and will start the date of such publication. Written comments on this document should be directed to:

Madhav Patil
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Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109
mpatil@baaqmd.gov

12. Glossary of Acronyms

AAQS	Ambient Air Quality Standard
ARB	Air Resource Board
BTU	British Thermal Unit
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
Cal ISO	California Independent System Operator
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CEM	Continuous Emission Monitor
CEQA	California Environmental Quality Act
CO	Carbon Monoxide
CO2	Carbon Dioxide
CPUC	California Public Utilities Commission
CTG	Combustion Turbine Generator
EO/APCO	Executive Officer/Air Pollution Control Officer
EPA	Environmental Protection Agency
ERC	Emission Reduction Credit
FDOC	Final Determination of Compliance
FSNL	Full Speed No Load
GE	General Electric Company
GHG	Greenhouse Gases
GT	Gas Turbine

MW	Megawatt
NH3	Ammonia
N2	Nitrogen
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NOx	Nitrogen Oxides
NSR	New Source Review
O2	Oxygen
LAER	Lowest Achievable Emissions Rate
LLC	Limited Liability Company
MEP	Mariposa Energy Project
MMBtu	Million Btu
NAAQS	National Ambient Air Quality Standard
PAH	Polycyclic Aromatic Hydrocarbon
PDOC	Preliminary Determination of Compliance
PG&E	Pacific Gas & Electric Company
PM10	Particulate Matter less than 10 Microns in Diameter
PM2.5	Particulate Matter less than 2.5 Microns in Diameter
POC	Precursor Organic Compounds
ppmvd	Parts Per Million by Volume, Dry
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
SCAQMD	South Coast Air Quality Management District

SNCR	Selective Non-catalytic Reduction
SCR	Selective Catalytic Reduction
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO2	Sulfur Dioxide
SOx	Sulfur Oxides
TAC	Toxic Air Contaminant
TBACT	Toxics Best Available Control Technology
U.S. EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

Appendix A
Emission Calculations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to estimate and verify criteria pollutant and toxic air contaminant emissions submitted in the permit application. The criteria emission calculations were prepared by the Applicant's consultant and are based on a combustion model. The District has verified these values using the calculations shown below. For the toxic air contaminants the District revised the calculation submitted by the Applicant.

standard temperature[a]:	70°F
standard pressure[a]:	14.7 psia
molar volume:	386.8 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8743 dscf/MM Btu
natural gas higher heating value:	1020 Btu/dscf

a. BAAQMD standard conditions per Regulation 1, Section 228.
b. F-factor is based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Value shown reflects the typical composition and heat content of utility-grade natural gas in San Francisco bay area.

Table A-1 summarizes the regulated air pollutant emission factors that were used to calculate mass emission rates for each source. All units are pounds per million Btu of natural gas fired based upon the high heating value (HHV). All emission factors are after abatement by applicable control equipment.

TABLE A-1
CONTROLLED REGULATED AIR POLLUTANT EMISSION FACTORS FOR GAS TURBINES

	Source	
	Simple-Cycle Each Gas Turbine[a]	
Pollutant	**lb/MMBtu**	**lb/hr**
Nitrogen Oxides (as NO_2) [b]	0.00915	4.40
Carbon Monoxide [c]	0.00446	2.14
Precursor Organic Compounds [d]	0.00255	1.22
Particulate Matter (PM_{10})	NA	2.5
Sulfur Dioxide (max hourly) [e]	0.0028	1.35
Sulfur Dioxide (Annual Average) [f]	0.00070	0.34

[a] Based upon a maximum turbine firing rate of 481 MMBtu/hour (HHV, 100% Load, 46ºF)
[b] Based upon stack concentration of 2.5 ppmvd NO_x @ 15% O_2 which reflects the use of Selective Catalytic Reduction Systems with ammonia injection.
[c] Based upon the permit condition emission limit of 2 ppmvd CO @ 15% O_2 which reflects the use of oxidation catalysts.
[d] Based upon the permit condition emission limit of 2 ppmvd POC @ 15% O_2 which reflects the use of oxidation catalysts.
[e] Maximum SO_x emissions based on 1 grain sulfur per 100 scf of natural gas.
[f] Average SO_x emissions based on 0.25 grains sulfur per 100 scf of natural gas.

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

The NOx emissions from the simple-cycle gas turbines will be 2.5 ppmv, dry @ 15% O2. This concentration is converted to a mass emission factor as follows:

(2.5 ppmvd)(20.95 - 0)/(20.95 - 15) = 8.80 ppmv NO_x, dry @ 0% O_2

($8.80/10^6$)(1 lbmol/386.8 dscf)(46 lb NO_2/lbmol)(8743 dscf/MMBtu) **= 0.00915 lb NO_2/MMBtu**

Calculations shown below are based on emission factors submitted by the Applicant.

The NO_x(as NO_2) mass emission rate based upon the maximum firing rate of the simple-cycle gas turbine is calculated as follows:

(0.00915 lb/MMBtu)(481 MMBtu/hr) = **4.40 lb NO_x(as NO_2)/hr**

CARBON MONOXIDE EMISSION FACTORS

The CO emissions from the simple-cycle gas turbines will be conditioned to a maximum controlled CO emission limit of 2 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

$(2\ ppmvd)(20.95 - 0)/(20.95 - 15) = 7.04$ ppmv, dry @ 0% O_2

$(7.04/10^6)$(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MMBtu) **= 0.00446 lb CO/MMBtu**

Calculations shown below are based on emission factors submitted by the Applicant.

The CO maximum mass emission rate based upon the maximum firing rate of the simple-cycle gas turbine is calculated as follows:

(0.00446 lb/MMBtu)(481 MMBtu/hr) = **2.14 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

The POC emissions from the simple-cycle gas turbines will be conditioned to a maximum controlled emission limit of 2 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The POC emission factor corresponding to this emission concentration is calculated as follows:

$(2\ ppmvd)(20.95 - 0)/(20.95 - 15) = 7.04$ ppmv, dry @ 0% O_2

$(7.04/10^6)$(lbmol/386.8 dscf)(16 lb CH_4/lbmol)(8743 dscf/MMBtu) = **0.00255 lb POC/MMBtu**

Calculations shown below are based on emission factors submitted by the Applicant.

The POC mass emission rate based upon the maximum firing rate of the simple-cycle gas turbine is calculated as follows:

(0.00255 lb/MMBtu)(481 MMBtu/hr) = 1.22 lb POC/hr

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

The District has determined a PM_{10} emission rate of **2.5 lb/hr** corresponds to BACT for the simple-cycle gas turbines.

SULFUR DIOXIDE EMISSION FACTORS

The SO_2 emission factor is based upon annual average natural gas sulfur content of 0.25 grains per 100 scf and a higher heating value of 1020 Btu/scf.

The sulfur emission factor is calculated as follows: SO_2 lb/hr

Natural Gas 1 grains of S/100 scf for Maximum Hourly

SO_2 = (1 gr/100 scf)(lb/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb SO_2/32 lb S) = 0.002801 lb/MMBtu

Natural Gas 0.25 grains of S/100 scf for Annual Average

SO_2 = (0.25 gr/100 scf)(lb/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb SO_2/32 lb S) = 0.000700 lb/MMBtu

Calculations shown below are based on emission factors submitted by the Applicant.

Max Hourly SO_2

The corresponding SO_2 emission rate for the simple-cycle gas turbine firing: (0.002801 lb SO_2/MMBtu)(481 MMBtu/hr) **= 1.35 lb/hr**

Annual Average SO_2

The corresponding SO_2 emission rate for the simple-cycle gas turbine firing: (0.000700 lb SO_2/MMBtu)(481 MMBtu/hr) **= 0.34 lb/hr**