BAY AREA
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DISTRICT
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March 16, 2005

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Mr. Robert Worl
Project Manager, Systems Assessment & Facility Siting Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento CA 95814

Re: Los Esteros Critical Energy Facility
BAAQMD Application 8859

Dear Mr. Worl:

This is to advise you that the BAAQMD has issued a revised Preliminary Determination of Compliance (PDOC) for the proposed conversion of the Los Esteros Critical Energy Facility (LECEF) from simple-cycle to combined-cycle operation. The LECEF is a 180-MW, natural gas fired, simple-cycle power plant located in San Jose north of Highway 237, between Zanker Road and Coyote Creek. The revised PDOC summarizes how the modified Los Esteros Critical Energy Facility will comply with applicable District regulations, including BACT and emission offset requirements. The PDOC is subject to the public notice and 30-day public comment requirements of District Regulations 2-2-405 and 406.

Enclosed is a copy of the Preliminary Determination of Compliance for this application and a copy of the Notice Inviting Written Public Comment. Please submit any written comments on the intended action to the APCO by April 25, 2005.

If you have any questions regarding this matter, please contact Dennis Jang, Air Quality Engineer, at (415) 749-4707.

Very truly yours,

Jack P Broadbent

Jack P. Broadbent
Executive Officer/APCO

Enclosure
JPB:dtj

Notice Inviting Written Public Comment

Notice is hereby given that the Air Pollution Control Officer (APCO) of the Bay Area Air Quality Management District has issued a revised Preliminary Determination of Compliance (PDOC) under application number 8859 for modifications to the **Los Esteros Critical Energy Facility** (LECEF), a nominal 180 megawatt, natural gas fired power plant located in San Jose north of Highway 237, between Zanker Road and Coyote Creek. The facility currently consists of four natural-gas fired, simple-cycle gas turbines. The modifications involve the conversion of the gas turbines to combined-cycle operation with a resulting nominal output of 320 megawatts. The PDOC documents the Air Pollution Control Officer's preliminary decision to issue an Authority to Construct for the proposed modifications to the Los Esteros Critical Energy Facility.

The existing power plant is currently permitted to emit the following maximum quantities of regulated air pollutants:

Nitrogen Oxides	75.2 tons per year
Carbon Monoxide	73.1 tons per year
Particulate Matter (PM_{10})	44.2 tons per year
Precursor Organic Compounds	20.8 tons per year
Sulfur Dioxide	5.8 tons per year

After the proposed modifications, the power plant will be permitted to emit the following maximum quantities of regulated air pollutants:

Nitrogen Oxides	99.2 tons per year
Carbon Monoxide	98.6 tons per year
Particulate Matter (PM_{10})	53.3 tons per year
Precursor Organic Compounds	28.3 tons per year
Sulfur Dioxide	8.4 tons per year

The emissions of nitrogen oxides (as NO_2), carbon monoxide, particulate matter (PM_{10}), precursor organic compounds, and sulfur dioxide associated with this project trigger the Best Available Control Technology (BACT) requirement of District Regulation 2-2-301.1. The emission increases of nitrogen oxides and precursor organic compounds associated with this project trigger the emission offset requirements of District Regulation 2-2-302.

Pursuant to District Regulation 2-2-405, the Air Pollution Control Officer invites written public comment on the Preliminary Determination of Compliance and its intended action.

The Preliminary Determination of Compliance is available for public inspection at the Public Information and Education Office located on the 5th floor of District headquarters at 939 Ellis Street, San Francisco CA, 94109. The PDOC may also be viewed on the District website at www.baaqmd.gov. Written comments should be directed to Dennis Jang of the District Permit Services Division by April 25, 2005.

Dated at San Francisco, the 16th day of March.

Jack P. Broadbent
Executive Officer/APCO
Bay Area Air Quality Management District

Preliminary
Determination of Compliance
(Revised)

Los Esteros Critical Energy Facility
Plant 13289

Combined-Cycle Conversion (Phase 2)

Bay Area Air Quality Management District
Application 8859

March 14, 2005

Dennis Jang, P.E.
Air Quality Engineer

PRELIMINARY DETERMINATION OF COMPLIANCE

LOS ESTEROS CRITICAL ENERGY FACILITY

Application 8859
Plant 13289

Background

This is the Preliminary Determination of Compliance (PDOC) for the conversion of the existing Los Esteros Critical Energy Facility (LECEF) from simple-cycle to combined-cycle operation. This conversion is referred to as Phase 2 and involves the addition of four heat recovery steam generators, one steam turbine generator and one six-cell cooling tower.

The LECEF currently consists of four natural gas-fired LM6000PC simple-cycle combustion turbines with a combined nominal output of 180 MW, a fire pump diesel engine, and a one-cell cooling tower that is exempt from District operating permit requirements. The LECEF is a wholly owned subsidiary of the Calpine Corporation.

The proposed modified LECEF facility will have a nominal output of 320 megawatts (MW) as a result of the addition of one nominal 140 MW steam turbine generator. In addition, the maximum rated heat input of each gas turbine will increase from 472.6 MM BTU/hr (HHV) to 500 MM BTU/hr (HHV). In accordance with BAAQMD Regulation 2-2-301, the gas turbines will meet current Best Available Control Technology (BACT) standards for NOx, CO, POC, SO_2, and PM_{10} emissions. Emission reduction credits will be provided to offset emission increases of precursor organic compounds. Because the facility emissions of all regulated air pollutants will remain less than 100 tons per year each, the LECEF is not subject to Prevention of Significant Deterioration (PSD) requirements.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the PDOC for the proposed modifications to the Los Esteros Critical Energy Facility. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #8859. In accordance with Regulation 2-3-405, the BAAQMD will issue the Authority to Construct after the CEC issues its certification for the proposed modifications to the LECEF.

The PDOC describes how the proposed modified facility will comply with applicable federal, state and BAAQMD regulations, including the BACT and emission offset requirements of the District New Source Review Regulation. Permit conditions will be imposed as needed to insure continuing compliance with applicable rules and regulations and calculated air pollutant emission rates.

In accordance with BAAQMD Regulation 2, Rule 3, Sections 405 & 406, the PDOC is subject to the public notice, public inspection, and public review and comment requirements of District Regulation 2, Rule 2, Sections 406 and 407.

This document is a revised version of the PDOC issued on September 28, 2004. The major differences between the two PDOC documents are summarized below:

- **After reviewing comments from the California Air Resources Board and EPA Region IX regarding the following permit condition that was included in the original Authority to Construct and Permit to Operate for the existing LECEF, the District has decided to conduct a BACT review for the proposed combined-cycle configuration of the LECEF.**

<u>Sunset Provision:</u> Within three years of CEC Approval, The owner/operator must convert to either a combined cycle or cogeneration plant using BACT in effect at the time of conversion. If conversion does not occur the plant must cease operation. (Basis: California State Resources Code, Section 25552)

- **The conclusion of the BACT review is that the combined-cycle LECEF must meet a NOx emission limit of 2.0 ppmv, dry @ 15% O_2, averaged over one-hour.**

- **The BACT review included a re-assessment of the CO emission concentration limit for the gas turbines/HRSGs that considers the decrease in the NOx limit from 2.5 to 2.0 ppmv. Consequently, the CO limit will be increased from 4 ppmv to 9 pppmv to allow for increased water injection rates at the gas turbine combustors. However, there will be no increase in the annual CO mass emission limit for the proposed combined-cycle facility.**

- **In the PDOC issued on September 28, 2004, the applicant accepted an emissions limit of 10 pounds of NOx (as NO_2) per day for each duct burner to insure that the duct burners would not trigger the BACT requirement of the District NSR Regulation. Because of the BACT determination cited above, the applicant has requested that the 10 pound per day limit be removed. Consequently, the duct burners trigger BACT since they each have a potential to emit NOx in excess of 10 pounds per day.**

- **In the PDOC issued on September 28, 2004, the applicant accepted an annual combined emissions limit of 74.9 tons of NOx (as NO_2) per year for the gas turbines and duct burners and a daily emission limit of 205.2 lb NOx/day to insure that the gas turbines would not trigger the BACT requirement of the District NSR Rule. Because of the BACT determination cited above, the applicant has requested that the original proposed combined annual NOx limit of 99.2 tons per year (as NO_2) and the proposed daily emission limit of 252.4 lb NOx/day be restored. The increases in annual and daily NOx emissions are due to duct burner firing. The quantity of emission offsets required has been changed accordingly.**

Permitted Source Descriptions:

The modified Los Esteros Critical Energy Facility will consist of the following permitted equipment after the combined-cycle conversion has been completed:

S-1 **Combustion Gas Turbine #1 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System**

S-2 Combustion Gas Turbine #2 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #3 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-4 Combustion Gas Turbine #4 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-5 Fire Pump Diesel Engine, Fairbanks Morse Model JW6H-UF40, 300 BHP, 14.5 gal/hr

S-7 Heat Recovery Steam Generator #1, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-1 Oxidation Catalyst, and A-2 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-3 Oxidation Catalyst, and A-4 Selective Catalytic Reduction System

S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-5 Oxidation Catalyst, and A-6 Selective Catalytic Reduction System

S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-7 Oxidation Catalyst, and A-8 Selective Catalytic Reduction System

S-11 Six-Cell Cooling Tower, 73,000 gallons per minute

The LECEF is currently equipped with a one-cell cooling tower for turbine inlet air and oil cooling. PM_{10} emissions from this tower are calculated to be 1.551 tons per year. This source is exempt from District permit requirements per Regulations 2-1-128.4 and 2-1-319.1, since it is not used for the evaporative cooling of process water and because the emissions are less than 5 tons per year.

As part of the Phase 2 conversion, a six-cell cooling tower with maximum PM_{10} emissions of 8 tons per year will be added. The six-cell cooling tower will require an authority to construct and permit to operate.

Emissions Control Strategy

The proposed project triggers the BACT requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (as NO_2), carbon monoxide (CO), precursor organic compounds (POC), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}). The combined-cycle LECEF will employ the following control technologies.

Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The S-1, S-2, S-3, and S-4 Gas Turbines will be equipped with water injection to reduce the combustion zone temperature and thereby reduce the formation of thermal NOx. The S-7, S-8, S-9, and S-10 HRSG duct burners will be installed downstream of the turbines but upstream of the existing oxidation catalyst and SCR system. The combined NO_x emissions from each turbine and corresponding HRSG will be reduced by a selective catalytic reduction (SCR) system with ammonia injection. In an SCR system, the nitrogen oxide emissions react with ammonia and diatomic oxygen in the presence of a precious metal catalyst to form diatomic nitrogen and water. Each gas turbine/HRSG pair will be subject to a NO_x emission concentration limit of 2.0 ppmvd @ 15% O_2 averaged over one hour.

Flue gas temperatures associated with simple-cycle gas turbines are generally higher than those of gas turbines used in combined-cycle. Simple-cycle gas turbine can have exhaust temperatures from 750°F to 1100°F. With combined-cycle gas turbines, exhaust heat is removed with a HRSG, resulting in stack gas temperatures ranging from 550°F to 750°F at the inlet to the SCR system. Because SCR catalysts perform best under defined temperature ranges, the existing high-temperature SCR catalysts will have to be replaced with conventional catalyst beds to insure satisfactory performance under the combined-cycle mode. Titanium dioxide and zeolyte catalysts are effective in the temperature range of 850°F to 1050°F. Vanadium pentoxide catalysts are effective in the temperature range of 550°F to 750°F.

Oxidation Catalyst to Minimize CO and POC Emissions

The S-1, S-2, S-3, and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs trigger BACT for CO and POC emissions. A catalyst designed to oxidize the CO and POC will be utilized to achieve a BACT-level CO emission limit of 9.0 ppmvd @ 15% O_2 (three hour average) and an annual facility cap of 98.6 tons/yr. The POC emission rate will be limited to 2.0 ppmvd @ 15 % O_2. Because CO oxidation catalysts typically operate at a higher temperature than SCR catalysts, the CO catalyst is installed upstream of the SCR system.

Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs will exclusively utilize natural gas as a fuel to minimize SO_2 and PM_{10} emissions. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

Emissions Calculations

Facility Emissions under Phase 2 (Combined-Cycle) Configuration:

The following projected operating scenario for S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10 was utilized to estimate the maximum annual air pollutant emissions from the gas turbines and HRSG duct burners. Actual operation will vary according to demand, plant maintenance, and equipment breakdowns.

- 7,260 hours of full load operation per turbine per year @ 29°F without HRSG duct burner firing
- 1,250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29°F
- 250 hours of start-up operation per year per gas turbine

This scenario is considered conservative because it assumes total operation of 8,760 hours per year per turbine at a minimum temperature of 29°F. In practice, the facility operation and actual emission rates will be affected by reduced turbine load, turbine down time, and a higher average ambient operating temperature. Because the temperature of the combustion air will typically be higher than 29°F, the air will be less dense, less natural gas will be burned, and the resulting mass emissions will be reduced accordingly.

Emission Factors:

NOx, CO, POC, and ammonia emissions will be subject to enforceable permit conditions that limit the exhaust concentration and mass emission rate for each pollutant. SO_2 and PM_{10} emissions will be subject to enforceable permit conditions that limit mass emission rates only.

Combined-Cycle Configuration (Phase 2):

Nitrogen Oxides (NOx as NO_2)

The applicant has agreed to a BACT-level NOx emission limit of 2.0 ppmv (averaged over one hour) for the combined-cycle configuration.

The NOx emissions (as NO_2) from the turbine will be limited by permit condition to 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 – 15) = 7.04 ppmv NOx, dry @ 0% O2

$(7.04/10^6)$(1 lbmol/385.3 dscf)(46.01 lb NO_2)/lbmol)(8600 dscf/MMBTU)
= 0.00723 lb NO_2/MMBTU

The hourly NO_2 mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.00723 lb NO_2/MM BTU)(500 MM BTU/hr) = **3.61 lb NO_2/hr**

The hourly NO_2 mass emission rate based on the maximum firing rate of a turbine and corresponding HRSG is calculated as follows:

(0.00723 lb NO_2/MM BTU)(639 MM BTU/hr) = **4.62 lb NO_2/hr**

Carbon Monoxide (CO)

The CO emission factor used to calculate **annual CO emissions** from each turbine is based upon an average CO emission concentration of 4.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(4.0 ppmvd)(20.95-0)/(20.95 – 15) = 14.08 ppmv CO, dry @ 0% O2

($14.08/10^6$)(1 lbmol/385.3 dscf)(28 lb CO)/lbmol)(8600 dscf/MMBTU)
= 0.0088 lb CO/MMBTU

The average hourly CO mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.0088 lb CO/MM BTU)(500 MM BTU/hr) = **4.4 lb CO/hr**

The average hourrly CO mass emission rate based on the maximum firing rate of the turbine and corresponding HRSG is calculated as follows:

(0.0088 lb CO/MM BTU)(639 MM BTU/hr) = **5.62 lb CO/hr**

The CO emission factor used to calculate **maximum short-term CO emissions** from each turbine is based upon the permit condition limit of 9.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(9.0 ppmvd)(20.95-0)/(20.95 – 15) = 31.69 ppmv CO, dry @ 0% O2

($31.69/10^6$)(1 lbmol/385.3 dscf)(28 lb CO)/lbmol)(8600 dscf/MMBTU)
= 0.02 lb CO/MMBTU

The maximum hourly CO mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.02 lb CO/MM BTU)(500 MM BTU/hr) = **9.9 lb CO/hr**

The maximum hourly CO mass emission rate based on the maximum firing rate of the turbine and corresponding HRSG is calculated as follows:

(0.02 lb CO/MM BTU)(639 MM BTU/hr) = **12.78 lb CO/hr**

Precursor Organic Compounds (POC)

The POC emissions (as methane) from the turbine will be limited by permit condition to 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 – 15) = 7.04 ppmv, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(16 lb CH_4)/lbmol)(8600 dscf/MMBTU)
= 0.0025 lb POC/MMBTU

The maximum hourly POC mass emission rate (as methane) based on the maximum firing rate of the turbine is calculated as follows:

(0.0025 lb POC/MM BTU)(500 MM BTU/hr) = **1.25 lb POC/hr**

The maximum hourly POC mass emission rate (as methane) based on the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.0025 lb POC/MM BTU)(639 MM BTU/hr) = **1.6 lb POC/hr**

Sulfur Dioxide (SO_2)

The SO_2 emission factor used to calculate **annual SO_2 emissions** is based upon an expected average natural gas sulfur content of 0.33 grains per 100 scf and a higher heating value of 1022 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(0.33 gr/100 scf)(10^6 BTU/MM BTU)(2 lb SO_2/lb S)(lb/7000 gr)(scf/1022 BTU)
= 0.00092 lb SO_2/MM BTU

The average hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine is calculated as follows:

(0.00092 lb SO_2/MM BTU)(500 MM BTU/hr) = **0.46 lb SO_2/hr**

The average hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.00092 lb SO_2/MM BTU)(639 MM BTU/hr) = **0.59 lb SO_2/hr**

The SO_2 emission factor used to calculate **maximum short-term SO_2 emissions** is based upon the maximum permit limit of 1.0 grains per 100 scf and a higher heating value of 1022 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(1.0 gr/100 scf)(10^6 BTU/MM BTU)(2 lb SO_2/lb S)(lb/7000 gr)(scf/1022 BTU)
= 0.0028 lb SO_2/MM BTU

The maximum hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine is calculated as follows:

(0.0028 lb SO_2/MM BTU)(500 MM BTU/hr) = **1.4 lb SO_2/hr**

The maximum hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.0028 lb SO_2/MM BTU)(639 MM BTU/hr) = **1.8 lb SO_2/hr**

PM_{10}

The PM_{10} emission factor of 2.5 lb/hr is based upon source testing results for the existing gas turbines at LECEF under simple-cycle operation. The duct burners that will be added for combined-cycle operation will not contribute significantly to the PM_{10} emissions from the gas turbines.

Ammonia (NH_3)

The ammonia (NH_3) mass emission rate from the turbines will be limited by permit condition to 10.0 ppmv, dry @ 15% O_2. The hourly NH_3 mass emission rate based on the maximum firing rate of each turbine is calculated as follows:

NH_3 emission concentration limit:	10.0 ppmv, dry @ 15% O_2
Dry exhaust gas flow rate (without duct burner):	238,868 dscfm @ 14.75% O_2
Dry exhaust gas flow rate (with duct burner):	236,649 dscfm @ 12.95% O_2

Correcting the ammonia concentration to actual oxygen content at full load without duct burner firing:

(10 ppmvd)(20.95 – 14.75)/(20.95 - 15) = 10.42 ppmvd @ 14.75% O_2

The ammonia mass emission rate at full load without duct burner firing is therefore:

(10.42 ppmvd/10^6)(238,868 dscfm)(60 min/hr)(lbmol/385.3 dscf)(17 lb NH_3/lbmol)
= **6.6 lb NH_3/hr**

The applicant has utilized a slightly higher emission factor of 6.70 lb NH_3/hr to calculate the maximum annual ammonia emissions utilized in the health risk assessment.

Based upon the maximum firing rate of the turbine, the maximum emission rate converts to the following emission factor:

(6.7 lb NH_3/hr)/(500 MM BTU/hr) = **0.134 lb NH_3/MM BTU**

Correcting the ammonia concentration to actual oxygen content at full load with duct burner firing:

(10 ppmvd)(20.95 – 12.95)/(20.95 - 15) = 13.44 ppmvd @ 12.95% O_2

The ammonia mass emission rate at full load with duct burner firing is therefore:

(13.44 ppmvd/10^6)(236,649 dscfm)(60 min/hr)(lbmol/385.3 dscf)(17 lb NH_3/lbmol)
= **8.42 lb NH_3/hr**

The applicant has utilized a slightly higher emission factor of 8.56 lb NH_3/hr to calculate the maximum annual ammonia emissions utilized in the health risk assessment.

Based upon the maximum firing rate of the turbine, the maximum emission rate converts to the following emission factor:

(8.56 lb NH_3/hr)/(639 MM BTU/hr) = **0.134 lb NH_3/MM BTU**

Table 1
Maximum Hourly Emission Factors for Combined-Cycle Configuration (lb/hour-turbine-HRSG)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Full Load without Duct Burner Firing[a]	3.61	1.25	2.5	9.9	1.4	6.7
Full Load with Duct Burner Firing[b]	4.62	1.6	2.5	12.78	1.8	8.56

[a]gas turbine at full load at maximum firing rate of 500 MM BTU/hr (HHV)

[b]gas turbine at full load with HRSG duct burner firing; maximum combined firing rate of 639 MM BTU/hour (HHV)

The gas turbine start-up/shutdown emission factors for NOx, POC and CO were provided by the applicant and based upon source testing data for the existing turbines at LECEF and similar turbines at other facilities. The emission rates for PM_{10} and SO_2 are assumed to not exceed full load emission rates since they are not affected by combustion efficiency or catalyst bed temperatures.

Table 2
Gas Turbine Start-up Emission Rates

	NO_2	POC	PM_{10}	CO	SO_2
lb/hr	40	12	2.5	41	1.4
lb/start[a]	160	48	10	164	5.6

[a]maximum start-up duration of 4 hours (240 minutes)

Maximum Daily Emissions for Gas Turbines and HRSGs:

Maximum daily emission estimates are based upon 24-hour per day operation at worst-case emission rates. For all pollutants, the maximum daily emissions occur during a day with one 4-hour start-up followed by 20 hours of full load gas turbine operation with duct burner firing at an ambient temperature of 29°F. The full load hourly emission estimates are based on the applicable permit condition emission concentration limits at 100% load. The start-up emission rates are based upon source test results from simple-cycle operation of the gas turbines at LECEF.

NO_2 = (40 lb/hr)(4 hr/start) + (4.62 lb/hr)(20 hr full load w/DB firing)
= 252.4 lb/day-turbine HRSG

CO = (41 lb/hr)(4 hr/start) + (12.78 lb/hr)(20 hr full load w/DB firing)
= 419.6 lb/day-turbine HRSG

POC = (12 lb/hr)(4 hr/start) + (1.61 lb/hr)(20 hr full load w/DB firing)
= 80.2 lb/day-turbine HRSG

PM_{10} = (2.5 lb/hr)(4 hr/start) + (2.5 lb/hr)(20 hr full load w/DB firing)
= 60 lb/day-turbine HRSG

SO_2 = (5.6 lb/hr)(4 hr/start) + (1.8 lb/hr)(20 hr full load w/DB firing)
= 58.4 lb/day-turbine HRSG

Annual Emissions For Gas Turbines and HRSGs:

The maximum annual emissions that form the basis of the permit condition limits for the four gas turbines and 4 HRSGs are based upon the following operating scenario:

- 7260 hours of full load operation per turbine per year @ 29°F without HRSG duct burner firing
- 1250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29°F
- 250 hours of start-up operation per year per gas turbine

The combined NO_x (as NO_2) and CO emissions from the turbines and HRSGs will be limited by permit condition to 99 tons/year and 98.6 tons/year, respectively. The accumulated mass emission totals for NOx and CO will be monitored by the continuous emission monitor (CEM) system. The other pollutants will be monitored by annual source testing and parametric correlation, if applicable. If any part of the CEM that is used for mass emission calculations is inoperative for more than three hours of plant operation, the mass emission rates will be calculated using alternative District-approved calculation methods.

NOx (as NO_2):

[(3.61 lb/hr)(7260 hr/yr) + (4.62 lb/hr)(1250 hr/yr) + (40 lb/hr)(250 hr/yr)](4 turbines)
= 167,934.4 lb NO_2/yr
= 83.967 ton/yr

POC:

[(1.25 lb/hr)(7260 hr/yr) + (1.6 lb/hr)(1250 hr/yr) + (12 lb/hr)(250 hr/yr)](4 turbines)
= 56,300 lb/yr
= 28.15 ton/yr

PM_{10}:

[(2.5 lb/hr)(7260 hr/yr) + (2.5 lb/hr)(1250 hr/yr) + (2.5 lb/hr)(250 hr/yr)](4 turbines)
= 87,600 lb/yr
= 43.8 ton/yr

CO:

[(4.4 lb/hr)(7260 hr/yr) + (5.62 lb/hr)(1250 hr/yr) + (41 lb/hr)(250 hr/yr)](4 turbines)
= 196,876 lb/yr
= 98.438 ton/yr

SO_2:

[(0.46 lb/hr)(7260 hr/yr) + (0.59 lb/hr)(1250 hr/yr) + (0.46 lb/hr)(250 hr/yr)](4 turbines)
= 16,768.4 lb/yr
= 8.384 ton/yr

NH_3:

[(6.7 lb/hr)(7260 hr/yr) + (8.56 lb/hr)(1250 hr/yr)](4 turbines)
= 237,368 lb/yr
= 118.7 ton/yr

Table 3
Fire Pump Diesel Engine Emission Rates

	NO_x (as NO_2)	POC	PM_{10}	CO	SO_2
Fire Pump Diesel Engine					
g/bhp-hr	6.7	0.06	0.07	0.25	0.14
lb/hr[a]	3.21	0.03	0.033	0.12	0.07
ton/yr[b]	0.214	0.002	0.002	0.008	0.004

[a]engine operation for discretionary purposes is limited to 45 minutes per day; limit imposed to minimize health risk assessment impact results

[b]100 hr/yr of discretionary operation on fuel with a maximum sulfur content of 0.05% and engine rating of 290 bhp.

One-Cell Cooling Tower

The LECEF is equipped with a one-cell cooling tower that is used for auxiliary cooling and turbine inlet air chilling as required during hot days. Although the tower will only be used on hot days, the emissions calculations are based upon the worst-case assumption of 24 hr/day, 8760 hr/yr operation.

It is conservatively assumed that all particulate matter emissions are PM_{10}.

Cooling tower circulation rate:	14,150 gpm
Maximum total dissolved solids:	10,000 ppm
Drift Rate:	0.0005 %

Water mass flow rate:

(14,150 gal/min)(60 min/hr)(8.34 lb/gal) = 7,080,660 lb/hr

Cooling Tower Drift:

(7,080,660 lb/hr)(0.000005) = 35.4 lb/hr

PM_{10} = (10,000 ppm)(35.4 lb/hr)/(10^6)
= 0.354 lb/hr
= 8.5 lb/day (24 hr/day operation)
= 3,101 lb/yr (8,760 operating hours per year)
= 1.551 ton/yr

As a result of the conversion of the LECEF to combined-cycle operation, a larger cooling tower will be required to handle the HRSG and steam turbine blowdown.

Six-Cell Cooling Tower

It is conservatively assumed that all particulate matter emissions are PM_{10}.

Cooling tower circulation rate:	73,000 gpm
maximum total dissolved solids:	10,000 ppm
Drift Rate:	0.0005 %

Water mass flow rate:

(73,000 gal/min)(60 min/hr)(8.34 lb/gal) = 36,529,200 lb/hr

Cooling Tower Drift:

(36,529,200 lb/hr)(0.000005) = 182.65 lb/hr

PM_{10} = (10,000 ppm)(182.65 lb/hr)/(10^6)
= 1.827 lb/hr
= 43.84 lb/day (24 hr/day operation)
= 16,000 lb/yr (8,760 operating hours per year)
= 8 ton/yr

Table 4
Current Permitted Maximum Annual Facility Emissions
Simple-Cycle Configuration
(tons/yr)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Turbines	74.9	20.8	43.8	72.9	5.8	110.7
Emergency Generator	0.09	0.07	0.014	0.15	2.3E-4	0
Fire Pump Diesel Engine	0.17	0.01	0.01	0.01	0.01	0
One-Cell Cooling Tower	-	-	0.4	-	-	-
Total	**75.2**	**20.8**	**44.2**	**73.1**	**5.8**	**110.7**
Current Permit Limit	**74.9**	**20.8**	**43.8**	**72.9**	**5.8**	**110.7**

Table 5 summarizes the maximum facility criteria pollutant emissions from the new combined-cycle facility. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the four SCR Systems.

Table 5
Maximum Annual Facility[1] Emissions, Combined-Cycle Configuration (tons/yr)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Turbines and HRSGs	83.967	28.150	43.800	98.438	8.384	118.7
Fire Pump Diesel Engine	0.214	0.002	0.002	0.008	0.004	0
One-Cell Cooling Tower	0	0	1.551	0	0	0
Six-Cell Cooling Tower	0	0	8.000	0	0	0
Total	**84.181**	**28.152**	**53.353**	**98.446**	**8.388**	**118.7**
Permit Limits	**99.2[2]**	**28.3**	**53.3**	**98.6**	**8.4**	**118**

[1]Because the natural gas fired emergency generator has been removed, it is not included in Table 5

[2]To allow for flexibility in the number of start-ups and duct firing rates, the applicant will provide sufficient emission reduction credits to offset the NOx emission increases resulting from this annual permit limit

Table 6 is a summary of the maximum toxic air contaminant (TAC) emissions from the LECEF in combined-cycle configuration. These emissions are used as input data for air pollutant dispersion models used to assess the health risk to the public resulting from TAC emissions from the facility.

Table 6
Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb/yr-project)
S-1, S-2, S-3, S-4 Gas Turbines, S-5 Fire Pump Diesel Engine, S-7, S-8, S-9, S-10 HRSGs, Exempt One-Cell Cooling Tower, S-11 Six-Cell Cooling Tower		
1,3-Butadiene[b]	7.8	1.1
Acetaldehyde[b]	721.5	72
Acrolein	65.3	3.9
Ammonia[c]	236,028	19,300
Arsenic	0	0.025
Benzene[b]	58.9	6.7
Cadmium	0	0.046
Copper	0	460
Diesel PM[b]	4.46	0.64
Ethylbenzene	576.5	193,000
Formaldehyde[b]	6,490.2	33
Hexane	4,580.3	83,000
Lead	0	16
Mercury	0	58
Naphthalene	29.4	270
Nickel[b]	72.6	0.73

Table 6
Maximum Facility Toxic Air Contaminant (TAC) Emissions (continued)

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb/yr-project)
S-1, S-2, S-3, S-4 Gas Turbines, S-5 Fire Pump Diesel Engine, S-7, S-8, S-9, S-10 HRSGs, Exempt One-Cell Cooling Tower, S-11 Six-Cell Cooling Tower		
PAHs[b]	3.2	0.044
Propylene	13,634.7	None specified
Propylene Oxide[b]	475.7	52
Toluene	2,352	38,600
Xylene	1,154.8	57,900
Zinc	1,754	6,800

[a]Pursuant to BAAQMD Toxic Risk Management Policy

[b]Carcinogenic compound

[c]Based upon the worst-case ammonia slip of 10 ppmvd @ 15% O_2 from the A-2, A-4, A-6 and A-8 SCR systems with ammonia injection

Based upon an analysis of cooling tower return water at the existing LECEF facility, no detectable amounts of arsenic, cadmium, copper, lead, or mercury were found. Therefore, it is expected that negligible quantities of those compounds will be emitted from the one-cell and six-cell cooling towers.

Compliance Determination

Regulation 2, Rule 2: New Source Review

The primary requirements of New Source Review that may apply to the proposed modifications to the Los Esteros Critical Energy Facility are Section 2-2-301, "Best Available Control Technology Requirement", and Section 2-2-302, "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR".

The proposed modifications to the LECEF are subject to BACT because, at the time Phase I was originally permitted, the applicant committed to use BACT when the LECEF was converted to a combined-cycle facility. This commitment is reflected in the final determination of compliance, authority to construct, and permit to operate for the Phase 1 (simple-cycle) Los Esteros Critical Energy Facility which included the following permit condition.

Sunset Provision: Within three years of CEC Approval, The owner/operator must convert to either a combined cycle or cogeneration plant using BACT in effect at the time of conversion. If conversion does not occur the plant must cease operation. (Basis: California State Resources Code, Section 25552)

The District has determined that this commitment is binding on the applicant as a permit condition contained in a District Authority to Construct.

The initial preliminary determination of compliance for the Phase 2 conversion of the LECEF issued by the District on September 28, 2004 concluded that the conversion did not trigger BACT for any pollutants because there would be no increase in emissions at the gas turbines and the potential to emit for the HRSG duct burners would be kept below 10 pounds per highest day for all pollutants. However, after reconsidering the permit condition in the Authority to Construct described above, the District has concluded that the LECEF conversion must apply BACT.

Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) 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.

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed project.

<u>BACT for S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10 Gas Turbine/HRSG Duct Burners</u>

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners. Because the permitted annual NOx emissions from the gas turbines will increase, they trigger the BACT provision of NSR. The HRSG duct burners will each trigger BACT for NOx because their potential to emit exceeds 10 pounds per day. It is assumed that the gas turbines and HRSGs trigger BACT for CO, POC, PM_{10}, and SO_2.

Because each gas turbine and its associated HRSG/duct burners will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/ HRSG power train as a combined unit.

The following BACT determinations for the proposed modifications to the LECEF meet or exceed the most recent recommendations adopted by the governing board of the California Air Resources Board (CARB) for large and small electric power generating power plants, as published in *Guidance for Power Plant Siting and Best Available Control Technology* (September 1999) and *Guidance for the Permitting of Electrical Generation Technologies* (July 2002).

Nitrogen Oxides (NO_x)

The LECEF is equipped with GE LM6000PC Sprint gas turbines with a nominal rating of 45 MW based upon a maximum firing rate of 472.6 MM BTU/hr. As part of the conversion to combined cycle operation, the maximum firing rate of each turbine will increase to 500 MM BTU/hr. As a result, the output of each turbine will increase to 49.4 MW. Because the permitted annual NOx emissions from the gas turbines will increase, they trigger BACT. Because the emissions from each gas turbine/HRSG duct burner power train will exhaust through a common exhaust, it is not possible to distinguish between emissions from each gas turbine versus those from the duct burner. Consequently, the increases in daily and annual emissions resulting from duct burner firing are attributed to turbines also with respect to whether or not BACT is triggered.

The simple-cycle LECEF is currently subject to a NO_x emission concentration limit of 5 ppmvd @ 15% O_2, averaged over three hours during all operating modes except gas turbine start-ups and shutdowns. The applicant originally proposed a NOx limit of 2.5 ppmvd @ 15% O_2, averaged over one hour as BACT for the combined-cycle configuration. This limit would apply to the combined exhaust from each gas turbine/HRSG power train. This limit meets the current BACT 2 (achieved in practice) determination of 2.5 ppmvd specified in District BACT Guideline 89.1.6.

The current (7/18/03) District BACT Guideline 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for combined cycle gas turbines with a rated output $\geq$ 40 MW as 2.0 ppmv NOx, dry @ 15% O_2 averaged over one hour. The guideline specifies BACT 2 (achieved in practice) as 2.5 ppmv NOx, dry @ 15% O_2, averaged over one hour with the observation that 2.0 ppmv NOx has been "achieved in practice" by a 50 MW combined cycle LM6000 sprint unit with water injection at the Valero Cogeneration Project. Based upon this BACT determination, the District issued a permit to the Pico Power Plant that included a NOx permit limit of 2.0 ppmv, dry @ 15% O_2 with limited allowable excursions due to transient situations such as rapid load changes.

This "achieved-in-practice" BACT determination was based upon the initial 3 months of operation of the Valero cogeneration unit that is subject to a NOx permit limit of 2.5 ppmv and is fired on either refinery fuel gas or natural gas. Subsequent review of 6 months of NOx CEM data from January through June of 2004 has shown that the Valero unit has not consistently complied with a NOx emission limit of 2.0 ppmv while firing refinery fuel gas. In some cases, the exceedances appear to be caused by rapid load changes at the gas turbine. In other cases, it is not clear what is causing the exceedances. However, there are several factors that could potentially cause those exceedances. One factor is that the SCR system at Valero is probably designed and operated to achieve 2.0 ppmv in order to provide a margin of compliance with the permit condition limit of 2.5 ppmv. Another factor is that refinery fuel gas typically has a higher heat content than natural gas. This results in a higher flame temperature that can result in higher NOx emissions. Because the effect of these factors cannot be definitively resolved, the achieved-in-practice BACT determination of 2.0 ppmv contained in the Pico Power Plant FDOC is considered by the District to have been made in error.

However, we can conclude that a NOx limit of 2.0 ppmv, dry averaged over one hour with limited allowable excursions due to transient conditions such as rapid load changes is technologically feasible based upon the performance of the Valero Cogeneration unit. A review of 4,009 valid clock hourly average NOx concentrations for the Valero Cogeneration Unit over a 6 month period shows that while the hourly average NOx emissions exceeded 2.0 ppmv on 514 occasions excluding start-up or other transient load conditions, the NOx concentration only exceeded 2.1 ppmv 89 times and exceeded 2.2 ppmv 42 times. This shows that the majority of exceedances were between 2.0 and 2.1 ppmv and indicates that the SCR system has been tuned to achieve a NOx emission level of 2.0 ppmv. The unit was fired on refinery fuel gas for 3,889 of those hours. When the unit was fired on natural gas (141 hours excluding start-up or transient load conditions) the NOx emission concentration did not exceed 1.9 ppmv. In addition, the CO emissions from the Valero Unit exceeded 4.0 ppmv only 7 times out of the 4,009 hours with a maximum hourly average emission concentration of 4.86 ppmv.

It is therefore reasonable to conclude that the Valero Unit is capable of achieving consistent compliance with a 2.0 ppmv NOx limit if the SCR system and water injection were tuned to comply with this emission level and if the unit was fired exclusively on natural gas.

As shown in the following table, it is also cost-effective to require this limit as calculated using District BACT cost-effectiveness calculation methods.

BACT Cost-effectiveness Calculation Summary

Case[a]	Total Annualized Cost[b] ($/year)	Emission Reduction ppmv; (tons/year)	Cost-Effectiveness ($/ton)
20 - 2.5 ppmv	$637,713	17.5 ppmv; (129.675)	$4,918
20 - 2.0 ppmv	$749,730	18 ppmv; (133.38)	$5,621

[a]assuming a NOx emission concentration from the turbine/HRSG power train prior to abatement is 20 ppmv

[b]see attached control equipment cost summary for derivation of annualized cost numbers

In conclusion, BACT for NOx for a new combined-cycle power plant employing the same size and type of gas turbine/HRSG configuration as the proposed modified Los Esteros Critical Energy Facility is deemed to be an emission concentration limit of 2.0 ppmvd, @ 15% O_2, averaged over one hour with limited allowable excursions due to transient conditions such as rapid load changes. The number of hours of excursions allowed will be proportional to those allowed for the recently permitted Pico Power Plant. This BACT determination is deemed to be technologically feasible and cost-effective in accordance with District BACT Guidelines.

The applicant has agreed to a NOx limit of 2.0 ppmvd @ 15% O_2, averaged over one hour with limited allowable excursions, not to exceed 5 ppmv. Because the water injection rate will be increased to enable the gas turbine to meet this limit, the CO emissions could potentially exceed the original BACT emission concentration limit of 4 ppmvd @ 15% O_2, averaged over 3 hours that was specified in the PDOC. Therefore, the applicant has requested a revised CO emission concentration limit of 9.0 ppmvd @ 15% O2. This will be discussed in greater detail the CO BACT section below.

Heat Recovery Steam Generators (HRSGs)

Supplemental heat will be supplied to the HRSGs with duct burners, which are designed to minimize NO_x emissions. The HRSG duct burners are subject to BACT since their potential to emit for NOx will exceed 10 pounds per day.

The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of 2.0 ppmvd @ 15% O_2, averaged over one hour. This satisfies BACT for NOx for this category of source.

Carbon Monoxide (CO)

District BACT Guideline 89.1.6, dated 7/18/03, specifies BACT (achieved in practice) for CO for a combined-cycle gas turbine with a power rating $\geq$ 40 MW as a CO emission concentration of 4.0 ppmv, dry @ 15% O_2, achieved through the use of an oxidation catalyst.

The basis of this BACT determination is the Sacramento Power Authority's Campbell Soup Cogeneration Facility that is permitted at 4.0 ppmvd CO @ 15% O_2, averaged over 3 hours while meeting a NOx emission limit of 3 ppmvd, averaged over three hours. The Campbell Soup Facility is equipped with a 103-MW Siemens V84 gas turbine equipped with DLN combustors. The Sacramento Municipal Utility District (SMUD) CEM data for the Campbell Soup facility shows at least 6 months of continuous compliance with their CO mass emission limit. Overall, the data shows very low CO concentrations of less than 1 ppm averaged over 24 hours.

The applicant originally agreed to a CO emission limit of 4 ppmvd @ 15% O_2 that would have applied to all gas turbine operating modes except for gas turbine start-up and shutdown. The applicant intended to comply with this limit through the use of an oxidation catalyst and combustor design. However, this proposed CO limit was based upon a NOx limit of 2.5 ppmv. Now that the NOx emission limit has been reduced from 2.5 ppmv to 2.0 ppmv, the applicant has requested that the maximum allowable (not-to-be-exceeded) CO limit be increased to 9.0 ppmv.

The LM 6000 Sprint gas turbines at LECEF utilize water injection and SCR for NOx control. For a given combustor type, NOx and CO emissions are inversely related. In the case of conventional combustors using water injection, the thermal NOx production is reduced by lowering the flame temperature through the injection of water at the combustors. However, this increases CO emissions since the lower flame temperature decreases combustion efficiency. The applicant intends to use increased water injection at the turbine combustor to meet the lower NOx limit. It is expected that CO emissions will increase and will likely exceed 4.0 ppmv on occasion.

There is no "achieved in practice" demonstration of a NOx emission level of 2.0 ppmv. Because NOx and CO emissions are inversely related, lowering NOx emissions will tend to increase peak CO emissions and make compliance with a "not-to-be exceeded" CO limit of 4.0 ppmv problematic. The District has determined that the CO emission levels achieved in practice while meeting higher NOx levels cannot be the basis for CO BACT at lower NOx levels.

Because no CO emission level has been achieved in practice for a NOx limit of 2.0 ppmv, the District must determine CO BACT based upon cost-effectiveness and technical feasibility. This application involves an existing source, with existing control equipment. The District's current cost-effectiveness criteria of CO is zero dollars per ton of CO reduced. The District has determined that additional reduction of CO (beyond achieved-in-practice levels) does not justify the additional cost.

The Valero Cogeneration Unit employs a LM6000 Sprint turbine with water injection and is subject to a CO limit of 6.0 ppmv. Based upon an analyis of 6 months of CEM data, the peak CO emission level was 4.86 ppmv. However, this was achieved within the context of a higher allowable NOx emission limit of 2.5 ppmv. It is expected that the peak CO emissions from the Valero Cogeneration Unit would increase and could exceed 6 ppmv if the NOx limit was reduced to 2.0 ppmv.

The applicant has attempted to decrease NOx emissions out of the turbine by increasing the water injection rate at the combustors. As the NOx emission concentration after abatement decreased from 4.1 ppmv to 2.7 ppmv, the CO emissions after abatement by the oxidation catalyst increased from 1.7 ppmv to 5.2 ppmv. It is expected that the CO emissions will increase further as the NOx emissions approach 2.0 ppmv.

Because the BAAQMD is in attainment for both the state and federal 1-hr and 8-hr ambient air quality standards for CO and the LECEF is not subject to PSD since the annual facility CO emission limit will remain 98.6 tons per year, the requested increase in the short-term CO emission concentration limit from 4.0 ppmv to 9.0 ppmv is acceptable given the corresponding air quality benefit that will be realized from the decrease in NOx emissions from 2.5 to 2.0 ppmv. Although the peak CO emission concentrations can be as high as 9.0 ppmv, the annual average CO emissions are not expected to exceed 4.0 ppmv. The CO emissions from the gas turbines and HRSGs will be continuously monitored and the facility will be operated to comply with the 98.6 ton per year limit on CO emissions.

We have performed a modeling analysis to determine the short-term impacts of CO emissions at 9 ppmv. As shown below, the 1-hr and 8-hr average CO impacts are both below District significance levels and the state and federal ambient air quality standards for CO.

Short-Term Modeled Impacts of CO Emissions at 9 ppmv

Averaging Period	Maximum Modeled Impacts ($\mu g/m^3$)	District Significance Levels ($\mu g/m^3$)	State Ambient Air Quality Standards ($\mu g/m^3$)	Federal Ambient Air Quality Standards ($\mu g/m^3$)
1-hour	85.3	2000	23,000	40,000
8-hour	57.2	500	10,000	10,000

As stated earlier, the BAAQMD is in attainment for both the state and federal ambient air quality standards for CO. The maximum ambient CO concentration recorded in the San Jose area has been trending downward. During calendar year 2003, the maximum recorded 1-hr and 8-hr average CO emission concentrations were 6,270 $\mu g/m^3$ and 4,560 $\mu g/m^3$, respectively.

Precursor Organic Compounds (POCs)

District BACT Guideline 89.1.6, dated 7/18/03, specifies BACT (achieved in practice) for POC for a combined cycle gas turbine with a power rating > 40 MW as a POC emission concentration of 2.0 ppmv, dry @ 15% O_2, typically achieved through the use of an oxidation catalyst in conjunction with combustion modifications.

Because CEMs for organic compounds only measure carbon (as C_1), it is not possible to determine non-methane/ethane hydrocarbon concentrations on a real-time basis. As a result, a continuous emission concentration limitation as BACT for POC is not feasible. Therefore, BACT for POC is deemed to be a concentration limitation to be verified by annual source testing. The POC emissions from the combustion turbine will be reduced to less than 2.0 ppmvd through the use of an oxidation catalyst. POC emissions are also minimized through the use of best combustion practices and "clean burning" natural gas.

Sulfur Dioxide (SO_2)

District BACT Guideline 89.1.6, dated 8/18/03, specifies BACT (achieved in practice) for SO_2 for a combined cycle gas turbine with a rated output > 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of 1 gr/100 scf. The gas turbines will utilize exclusively natural gas with a maximum sulfur content of 1.0 gr/100 scf to minimize SO_2 emissions. Annual emission estimates are based upon an average fuel sulfur content of 0.33 gr/100 scf. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of natural gas will result in the lowest possible emission of SO_2.

Particulate Matter (PM_{10})

District BACT Guideline 89.1.6, dated 7/18/04, specifies BACT (achieved in practice) for PM_{10} for a combined-cycle gas turbine with a rated output > 40 MW as the exclusive use of clean-burning natural gas with a sulfur content of 1 gr/100 scf. The proposed turbines will utilize natural gas exclusively with a maximum sulfur content of 1.0 gr/100 scf and an annual average sulfur content of 0.33 gr/100 scf, which will result in minimal nitrate and sulfate particulate formation. In general, PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

<u>BACT for S-11 Six-Cell Cooling Tower</u>

Particulate Matter (PM_{10})

The proposed six-cell cooling tower is subject to BACT for PM_{10} since its potential to emit exceeds 10 pounds per day for that pollutant.

The BAAQMD BACT/TBACT workbook does not specify BACT for PM_{10} for wet cooling towers. However, the ARB BACT Clearinghouse cites a BACT specification for PM_{10} for the proposed La Paloma power plant cooling tower as the use of drift eliminators with a maximum drift rate of 0.0006%. The cooling towers for the Los Medanos Energy Center, Delta Energy Center, Metcalf Energy Center, East Altamont Energy Center, and Tesla Power Project are or will be equipped with drift eliminators with a guaranteed drift rate of 0.0005%.

The six-cell cooling tower proposed for the combined-cycle LECEF will also be equipped with drift eliminators with a guaranteed drift rate of 0.0005%. Therefore, S-11 Cooling Tower satisfies BACT for PM_{10}.

Emission Offsets

Table 8
Permitted Maximum Annual Emissions, Combined-Cycle Configuration (tons/yr)

	NO_2	POC	CO	SO_2	PM_{10}
Current Facility Emission Permit Limits (tpy)	74.9	21.0	72.9	5.8	43.8
Combined-Cycle Facility Emission Permit Limits (tpy)	99.2	28.3	98.6	8.4	62
Emission Increase (tpy)	24.3	7.300	25.7	2.6	18.2
Offset Ratio	1.15:1.0	1.0:1.0	N/A	N/A	N/A
Offsets Required (tpy)	27.945	7.300	0	0	0

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increase associated with this project because the facility 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 not opted to provide such emission offsets.

Pursuant to Regulation 2-2-302, federally enforceable emission reduction credits are required for NOx and POC increases at a ratio of 1.15:1.0 and 1.0:1.0, respectively. As shown in Table 9, below, the applicant has demonstrated that it possesses sufficient valid NOx and POC emission reduction credits to offset the POC and NOx emission increases for this project, and will submit certificates before the Authority to Construct is issued. Pursuant to Regulation 2-2-302.2, the applicant has opted to provide POC emission reduction credits to offset some of the NOx emission increases resulting from the proposed modifications to the facility.

As indicated below, Calpine has secured sufficient valid emission reduction credits to offset the emission increases resulting from the modifications to the existing permitted sources and new sources proposed for the Los Esteros Critical Energy Facility. These ERCs are summarized in the table below. The outstanding balance of 0.449 tons of POC will be re-issued and returned to the applicant.

Table 9 Emission Reduction Credits Identified by Calpine as of June 10, 2004 (tons/yr)

Current Owner	Certificate Number	Pollutant Quantity (tpy)		Origin, Location	Date Banked
		POC	NOx		
Calpine	856	26.522	0	Myers Container, San Pablo	4/23/02
Calpine	822	0	1.029	Philips Semiconductor, Sunnyvale	8/6/93
LECEF	724	0	7.100	Cardinal Cogen, Palo Alto	3/13/96
Calpine	786	0.017	1.026	North American Refractories, Pittsburg	11/15/01
Total Offsets Available		26.539	9.155		
Offset Obligation		7.300	27.945		
Difference		+19.239	18.790		
Balance		0.449	0		

Pursuant to District Regulation 2-2-311, the applicant must provide the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, *Power Plants*, the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant.

Prevention of Significant Deterioration (PSD)

Pursuant to Regulation 2-2-304, a PSD air quality analysis is not required because the modified LECEF will emit less than the trigger levels listed below for NO_2, POC, PM_{10}, CO, and SO_2. Therefore, the project will not be subject to PSD review for those pollutants.

Table 10
Combined-Cycle Facility Emissions and PSD Trigger Levels

Pollutant	PSD Trigger Level for New Facilities (tpy)	Phase 2 LECEF Potential to Emit (tpy)
NO_x	100	99.2
POC	100	28.3
PM_{10}	100	62.1
CO	100	98.6
SO_2	100	8.4
SAM	7	< 7

The sulfuric acid mist (SAM) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. An enforceable permit condition has been included (part 23) limiting combined sulfuric acid mist from the gas turbines and HRSGs to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in part 27 of the permit conditions, to measure SO_2, SO_3, and SAM. This approach is necessary because the extent to which fuel sulfur is converted to SO_3 and then to sulfuric acid mist when it is combusted in a gas turbine has not been established.

Regulation 2, Rule 2, Sections 406 and 407: Public Notice, Comment, and Inspection

Because the California Energy Commission has accepted an Application for Certification for this plant, the plant is subject to District Regulation 2, Rule 3 that governs power plants. Pursuant to Regulation 2-3-404, this project is subject to the Public Notice, Public Comment and Public Inspection requirements contained in Sections 2-2-406 and 407 of Rule 2. Pursuant to these regulations a notice inviting written public comment on the initial PDOC was published in the San Jose Mercury News on November 4, 2004. The notice included the preliminary decision of the APCO to issue an authority to construct for the proposed phase II modifications to the LECEF, how the public could obtain further information regarding the modifications, and invited written public comment period for a period of 30 calendar days from the date of publication. A similar notice will be published in the San Jose Mercury News for this revised PDOC.

California Environmental Quality Act (CEQA) Analysis

The CEQA requirements of District Regulation 2-1-426 are met because the California Energy Commission (CEC) is the lead agency on this project and is thus responsible for complying with CEQA. The CEC's final certification and licensure will serve as the EIR equivalent pursuant to the CEC's certified regulatory program (CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523).

BAAQMD Toxic Risk Management Policy

Pursuant to the BAAQMD Toxic Risk Management Policy (TRMP), a health risk screening analysis must be performed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the project. In accordance with the requirements of the BAAQMD TRMP and California Air Pollution Control Officers Association (CAPCOA) guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

The District's Toxics Evaluation Section performed a review of the health risk assessment submitted by the applicant for operation of the combined cycle gas turbine configuration of the LECEF. The emission rates used in that analysis are calculated based on an annual fuel use of 16,560,000 MMBTU (16,200 MMscf/yr.). The ammonia emissions rates were based upon a worst-case ammonia slip emission concentration of 10 ppmvd @ 15% O_2 from the SCR systems. The remainder of the TAC emissions, except for PAHs, hexane and propylene, were calculated using the emission factors from the AP-42 Background Document published by US-EPA in April 2000. California Air Toxics Emission Factor (CATEF II) database mean emission factors, available from the California Air Resources Board (CARB) for gas turbines with COC/SCR controls, were used for PAHs, hexane and propylene. Emissions from four gas turbines, four HRSGs, the one-cell and six-cell cooling towers, and fire pump diesel engine have been included in this risk screening analysis. The natural gas fired emergency generator was never and will not be installed and is therefore not included in the risk screening analysis.

Table 11
Risk Screening Analysis Results

Cancer Risk	Chronic Hazard Index
2.8 in one million	0.006

Pursuant to the BAAQMD Toxic Risk Management Policy (TRMP), the increased carcinogenic risk attributed to this project is acceptable since it is less than 10 in one million and TBACT is employed on all sources subject to the risk screening.

The fire pump diesel engine, which is the primary contributor to the total risk of 2.8 in one million employs TBACT since it has been CARB-certified (Executive Order U-R-004-0111) at a particulate matter emission rate of 0.1 g/bhp-hr. The gas turbines and HRSGs are abated by oxidation catalysts, which are considered TBACT for the products of incomplete combustion that are considered toxic air contaminants as listed in Table 6. The cooling towers are designed to achieve a drift rate of 0.0005% which is considered TBACT since it minimizes the emissions of carcinogenic heavy metals such as nickel.

Thus, in accordance with the BAAQMD Toxic Risk Management Policy, the screen passes.

Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed 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. In part, the air quality impact analysis is designed to insure that the proposed facility will comply with this Regulation.

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

Pursuant to Regulation 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 the proposed modifications to the LECEF, including the addition of the four heat recovery steam generators.

Regulation 2, Rule 2, Section 307: Denial, Failure of All Facilities to be in Compliance

Because the proposed modifications to the LECEF do not constitute a major modification of a major facility pursuant to 2-2-221, Regulation 2-2-307 does not apply. Under its current configuration, the LECEF is not a major facility. After the proposed modifications, the "combined-cycle" LECEF will not be a major facility. Therefore, Calpine is not required to submit a certification that all of their major facilities located in the State of California are either in compliance or on a schedule of compliance with all applicable state and federal emission limitations and standards.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Preliminary Determination of Compliance (PDOC) serves as the APCO's decision that the proposed modified power plant will meet the requirements of all applicable BAAQMD, state and federal regulations. The PDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-403, the PDOC is subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the PDOC is not considered a final determination of whether the facility can be constructed or operated. The authority to construct will be issued after the modified LECEF is certified by the California Energy Commission.

Regulation 2, Rule 6: Major Facility Review

Title V of the 1990 Clean Air Act Amendments (CAAA) requires states to implement and administer a source-wide operating permit program consistent with the provisions of Title 40, Code of Federal Regulations (CFR), Part 70. The BAAQMD administers the Title V program through Regulation 2, Rule 6. The Title V operating permit was issued for the existing configuration of the LECEF on June 4, 2004. Because the proposed changes to the LECEF facility constitute a major modification under Title V, a modified Title V permit must be issued prior to first fire of the combined-cycle LECEF. The owner/operator has not submitted an application to modify the Title V permit as of the date of this document.

Regulation 2, Rule 7: Acid Rain

The LECEF is a Phase II Acid Rain Facility pursuant to Regulation 2-6-217.1. The modified LECEF will also be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are set forth in 40 CFR Parts 72, 73, and 75. 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.

The project will be subject to the following general requirements under the acid rain program:

- Duty to apply for a modification to the Acid Rain Permit
- Compliance with SO_2 and NOx emission limits
- Duty to obtain required SO_2 allowances
- Duty to install, operate and certify Continuous Emission Monitoring Systems (CEMs) to demonstrate compliance with the acid rain requirements

The applicant will secure the required SO_2 allowances and will perform the required emission monitoring. In accordance with applicable federal regulations, the applicant will submit appropriate monitoring plans. The Title IV (Acid Rain) permit was issued for the existing configuration of the LECEF on June 4, 2004. Because the proposed changes to the LECEF facility constitute a major modification under Title V, a modified Title IV/V permit must be issued prior to first fire of the combined-cycle LECEF. The owner/operator has not submitted an application to modify the Title IV/V permit as of the date of this document.

Regulation 6: Particulate Matter and Visible Emissions

The combustion of natural gas at the proposed gas turbines and HRSGs is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including 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.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from each of the proposed SCR systems will be limited by permit condition to 10 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

The gas turbines and HRSG duct burners are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Regulation 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry.

The use of solvents for cleaning and maintenance at the TPP is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" Section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

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 ppm (dry). The gas turbine is not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with Section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The gas turbines (each rated at 500 MM BTU/hr, HHV) and proposed HRSG duct burners (each rated at 139 MM BTU/hr, HHV) will comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition NOx emission limit of 2.0 ppmvd @ 15% O_2. The fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 1.89 MM BTU/hr, based upon a maximum diesel fuel use rate of 13.5 gallons per hour.

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

The 300 hp fire pump diesel engine is exempt from the requirements of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The S-5 Fire Pump Diesel Engine will continue to comply with Regulation 9-8-330 which allows unlimited emergency use and limits discretionary use to 100 hours per year.

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

Because the combined exhaust from the combustion gas turbines and HRSG duct burners will be limited by permit condition to NO_x emissions of 2.0 ppmvd @ 15% O_2 (verified by CEM), the gas turbines will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: New Source Performance Standards (NSPS)

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60, New Source Performance Standards. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Db, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units", and Subpart GG "Standards of Performance for Stationary Gas Turbines". The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. Subpart Db applies to the heat recovery steam generators and Subpart GG applies to the gas turbines. The applicable emission limitations are summarized below:

Applicable New Source Performance Standards

Source	Requirement	Emission Limitation	Compliance Verification
Gas Turbines and HRSGs	Subpart Db		
	40 CFR 60.44b(a)(1)(ii)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 2.0 ppmvd @15% O_2. This is equivalent to 0.00723 lb NOx/MM BTU
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Gas Turbines limited by permit condition to 2.0 ppmv NOx @ 15% O_2, dry, verified by CEM

Section 112 of the Clean Air Act, National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Gas Turbines, which was promulgated on March 5, 2004, does not apply to the proposed modified LECEF since it was constructed prior to 1/14/03 and the proposed combined-cycle conversion of the existing gas turbines at the LECEF does not constitute a "reconstruction" of the gas turbines because the conversion does not involve the replacement of any components of the turbines. This definition of "Reconstruction" is given in 40 CFR Part 63, Subpart A, Section 63.2, "Definitions".

CEQA

The CEQA requirements of Districts Regulation 2-1-426 are met because the California Energy (CEC) is the lead agency on this project. The CEC is thus responsible for conducting the CEQA review and preparing the CEQA document for this project. The CEC's final certification and license will serve as the EIR equivalent pursuant to the CEC's certified regulatory program as specified in CEQA Guidelines Section 15253(b) and Public Resources Code Sections 21080.5 and 25523.

Permit Conditions (Combined-Cycle Configuration)

Definitions:

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
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 fifteen-minute increments.
MM BTU:	million British thermal units
Gas Turbine Start-up Mode:	The time beginning with the introduction of continuous fuel flow to the Gas Turbine until the requirements listed in Part 19 are

	satisfied. In no case shall the duration of a start-up exceed 240 minutes.
Gas Turbine Shutdown Mode:	The time from non-compliance with any requirement listed in part 19 until termination of fuel flow to the Gas Turbine, but not to exceed 30 minutes.
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO or NH_3) corrected to a standard stack gas oxygen concentration. For an emission point (exhaust of a Gas Turbine) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the 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.
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 following the installation of the duct burners and associated equipment, 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. The Commissioning Period shall not exceed 180 days under any circumstances.
Alternate Calculation:	A District approved calculation used to calculate mass emission data during a period when the CEM or other monitoring system is not capable of calculating mass emissions.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

EQUIPMENT DESCRIPTION:

This Authority To Construct Is Issued And Is Valid For This Equipment Only While It Is In The Configuration Set Forth In The Following Description:

Four Combined-Cycle Gas Turbine Generator Power Trains consisting of:

1. Combined-Cycle Gas Turbine, General Electric LM6000PC, Maximum Heat Input 500 MMBTU/hr (HHV), 49.4 MW, Natural Gas-Fired

2. Heat Recovery Steam Generator, equipped with low-NOx duct burners, 139 MM BTU/hour, natural gas fired

3. Selective Catalytic Reduction (SCR) NOx Control System.

4. Ammonia Injection System.
(including the ammonia storage tank and control system)

5. Oxidation Catalyst (OC) System.

6. Continuous emission monitoring system (CEMS) designed to continuously record the measured gaseous concentrations, and calculate and continuously monitor and record the

NOx and CO concentrations in ppmvd corrected to 15% oxygen on a dry basis. The CEM shall also calculate, using District approved methods, and log any mass limits required by these conditions.

PERMIT CONDITIONS:

Conditions for the Commissioning Period

1. The owner/operator of the Los Esteros Critical Energy Facility shall minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators to the maximum extent possible during the commissioning period. Parts 1 through 11 shall only apply during the commissioning period as defined above. Unless noted, parts 12 through 49 shall only apply after the commissioning period has ended. (basis: cumulative increase)

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 Turbine combustors to minimize the emissions of carbon monoxide and nitrogen oxides. (basis: cumulative increase)

3. At the earliest feasible opportunity and in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall install, adjust and operate the SCR Systems (A-2, A-4, A-6 & A-8) and OC Systems (A-1, A-3, A-5 & A-7) to minimize the emissions of nitrogen oxides and carbon monoxide from S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators. (basis: cumulative increase)

4. Coincident with the steady-state operation of SCR Systems (A-2, A-4, A-6, & A-8) and OC Systems (A-1, A-3, A-5, & A-7) pursuant to part 3, the owner/operator shall operate the facility in such a manner that the Gas Turbines (S-1, S-2, S-3 and S-4) comply with the NOx and CO emission limitations specified in parts 19a and 19c. (basis: BACT, offsets)

5. The owner/operator of the Los Esteros Critical Energy Facility shall submit a plan to the District Permit Services Division at least two weeks prior to first firing of S-1, S-2, S-3 & S-4 Gas Turbines and/or S-7, S-8, S-9, & S-10 HRSGs describing the procedures to be followed during the commissioning of the turbines in the combined-cycle configuration. 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 tuning of the water injection, 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, S-2, S-3 and S-4) without abatement by their respective SCR Systems. The Gas Turbines (S-1, S-2, S-3 and S-4) shall be fired in combined cycle mode no sooner than fourteen days after the District receives the commissioning plan. (basis: cumulative increase)

6. During the commissioning period, the owner/operator of the Los Esteros Critical Energy Facility shall demonstrate compliance with parts 8 through 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   a. firing hours
   b. fuel flow rates
   c. stack gas nitrogen oxide emission concentrations,

d. stack gas carbon monoxide emission concentrations
e. 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 S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators. The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request. (basis: cumulative increase)

7. The owner/operator shall install, calibrate and make operational the District-approved continuous monitors specified in part 6 prior to first firing of each turbine (S-1, S-2, S-3 and S-4 Gas Turbines) and HRSG (S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators). After first firing of the turbine, 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: BAAQMD 9-9-501, BACT, offsets)

8. The owner/operator shall not operate the facility such that the number of firing hours of S-1, S-2, S-3 and S-4 Gas Turbines and/or S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators without abatement by SCR or OC Systems exceed 250 hours during the commissioning period. Such operation of the S-1, S-2, S-3 and S-4 Gas Turbines without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or OC system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 250 firing hours without abatement shall expire. (basis: offsets)

9. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in part 22. (basis: offsets)

10. The owner/operator shall not operate the facility such that the pollutant mass emissions from each turbine (S-1, S-2, S-3 and S-4 Gas Turbines) and corresponding HRSG (S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators) exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the S-1, S-2, S-3 and S-4 Gas Turbines.

	Without Controls		With Controls	
a. NO_x (as NO_2)	1464 lb/day	102 lb/hr	1464 lb/day	61 lb/hr
b. CO	1056 lb/day	88 lb/hr	984 lb/day	41 lb/hr
c. POC (as CH_4)	288 lb/day		114 lb/day	
d. PM_{10}	60 lb/day		60 lb/day	
e. SO_2	53.6 lb/day		53.6 lb/day	

(basis: cumulative increase)

11. Within sixty (90) days of startup, the owner/operator shall conduct a District approved source test using external continuous emission monitors to determine compliance with part 10. The source test 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 (30) days before the execution of the source tests, the owner/operator shall submit to the District a detailed source test plan designed to satisfy the requirements of this part. The owner/operator shall be notified 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 comments into the test plan. The owner/operator shall notify the District within ten (10) days prior to the planned source testing date. Source test results shall be submitted to the District within 60 days of the source testing date. These results can be used to satisfy applicable source testing requirements in Part 26 below. (basis: offsets)

Conditions for Operation:

12. Consistency with Analyses: Operation of this equipment shall be conducted in accordance with all information submitted with the application (and supplements thereof) and the analyses under which this permit is issued unless otherwise noted below. (Basis: BAAQMD 2-1-403)

13. Conflicts Between Conditions: In the event that any part herein is determined to be in conflict with any other part contained herein, then, if principles of law do not provide to the contrary, the part most protective of air quality and public health and safety shall prevail to the extent feasible. (Basis: BAAQMD 1-102)

14. Reimbursement of Costs: All reasonable expenses, as set forth in the District's rules or regulations, incurred by the District for all activities that follow the issuance of this permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by the owner/operator as required by the District's rules or regulations. (Basis: BAAQMD 2-1-303)

15. Access to Records and Facilities: As to any part that requires for its effective enforcement the inspection of records or facilities by representatives of the District, the Air Resources Board (ARB), the U.S. Environmental Protection Agency (U.S. EPA), or the California Energy Commission (CEC), the owner/operator shall make such records available or provide access to such facilities upon notice from representatives of the District, ARB, U.S. EPA, or CEC. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. (Basis: BAAQMD 1-440, 1-441)

16. Notification of Commencement of Operation: The owner/operator shall notify the District of the date of anticipated commencement of turbine operation not less than 10 days prior to such date. Temporary operations under this permit are granted consistent with the District's rules and regulations. (Basis: BAAQMD 2-1-302)

17. Operations: The owner/operator shall insure that the gas turbines, HRSGs, emissions controls, CEMS, and associated equipment are properly maintained and kept in good operating condition at all times. (Basis: BAAQMD 2-1-307)

18. Visible Emissions: The owner/operator shall insure that no air contaminant is discharged from the LECEF into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is as dark or darker than Ringelmann 1 or equivalent 20% opacity. (Basis: BAAQMD 6-301)

19. Emissions Limits: The owner/operator shall operate the facility such that none of the following limits are exceeded:

a. The emissions of oxides of nitrogen (as NO_2) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2.0 ppmvd @ 15% O_2 (1-hour rolling average), except during periods of gas turbine startup and shutdown as defined in this permit. The NOx emission concentration shall be verified by a District-approved continuous emission monitoring system (CEMS) and during any required source test. (basis: BACT)

b. Emissions of ammonia from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 10 ppmvd @ 15% O_2 (3-hour rolling average), except during periods of start-up or shutdown as defined in this permit. The ammonia emission concentration shall be verified by the continuous recording of the ratio of the ammonia injection rate to the NOx inlet rate into the SCR control system (molar ratio). The maximum allowable NH_3/NO_x molar ratio shall be determined during any required source test, and shall not be exceeded until reestablished through another valid source test. (basis: BACT)

c. Emissions of carbon monoxide (CO) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 9.0 ppmvd @ 15 % O_2 (3-hour rolling average), except during periods of start-up or shutdown as defined in this permit. The CO emission concentration shall be verified by a District-approved CEMS and during any required source test. (basis: BACT)

d. Emissions of precursor organic compounds (POC) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2 ppmvd @ 15% O2 (3-hour rolling average), except during periods of gas turbine start-up or shutdown as defined in this permit. The POC emission concentration shall be verified during any required source test. (basis: BACT)

e. Emissions of particulate matter less than ten microns in diameter (PM_{10}) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2.5 pounds per hour. The PM_{10} mass emission rate shall be verified during any required source test. (basis: BACT & cumulative increase)

f. Emissions of oxides of sulfur (as SO_2) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 1.8 pounds per hour. The SO_2 emission rate shall be verified during any required source test. (basis: BACT & cumulative increase)

g. Compliance with the hourly NO_x emission limitations specified in part 19(a), at emission points P-1, P-2, P-3, and P-4, shall not be required during short-term excursions, limited to a cumulative total of 320 hours per rolling 12 month period for all four sources combined. Short-term excursions are defined as 15-minute periods designated by the Owner/Operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O_2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling
(2) Initiation/shutdown of combustion turbine water mist or steam injection for power augmentation
(3) Rapid combustion turbine load changes
(4) Initiation/shutdown of HRSG duct burners
(5) Provision of ancillary services and automatic generation control at the direction of the California Independent System Operator (Cal-ISO)

The maximum 1-hour average NO_x concentration for short-term excursions at emission points P-1, P-2, P-3, and P-4 each shall not exceed 5 ppmv, dry @ 15% O_2. All emissions during short-term excursions shall be included in all calculations of hourly, daily and annual mass emission rates as required by this permit.

20. Turbine Start-up: The owner/operator shall operate the gas turbines so that the duration of a start-up does not exceed 240 minutes per event, or other time period based on good engineering practice that has been approved in advance by the District. The start-up period begins with the turbine's initial firing and continues until the unit is in compliance with all applicable emission concentration limits. (Basis: Cumulative increase)

21. Turbine Shutdown: The owner/operator shall operate the gas turbines so that the duration of a shutdown does not exceed 30 minutes per event, or other time period based on good engineering practice that has been approved in advance by the District. Shutdown begins with the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. (Basis: Cumulative increase)

22. Mass Emission Limits: The owner/operator shall operate the LECEF so that the mass emissions from the S-1, S-2, S-3 & S-4 Gas Turbines and S-7, S-8, S-9, & S-10 HRSGs do not exceed the daily and annual mass emission limits specified below. The owner/operator shall implement process computer data logging that includes running emission totals to demonstrate compliance with these limits so that no further calculations are required.

Mass Emission Limits (Including Gas Turbine Start-ups and Shutdowns)

Pollutant	Each Turbine/HRSG Power Train (lb/day)	All 4 Turbine/HRSG Power Trains (lb/day)	All 4 Turbine/HRSG Power Trains (ton/yr)
NOx (as NO_2)	252.4	1,009.6	99
POC	80.2	320.8	28.3
CO	419.6	1,678.4	98.6
SOx (as SO_2)	41.6	166.4	8.4
PM_{10}	60	240	43.8
NH_3	198	792	118

The daily mass limits are based upon calendar day per the definitions section of the permit conditions. The annual mass limit is based upon a rolling 8,760-hour period ending on the last hour. Compliance shall be based on calendar average one-hour readings through the use of process monitors (e.g., fuel use meters), CEMS, source test results, and the monitoring, recordkeeping and reporting conditions of this permit. If any part of the CEM involved in the mass emission calculations is inoperative for more then three consecutive hours of plant operation, the mass data for the period of inoperation shall be calculated using a District-approved alternate calculation method. (Basis: cumulative increase, recordkeeping)

23. Sulfuric Acid Mist Limit: The owner/operator shall operate the LECEF so that the sulfuric acid mist emissions (SAM) from S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10 combined do not exceed 7 tons totaled over any consecutive four quarters. (Basis: PSD)

24. Operational Limits: In order to comply with the mass emission limits of this rule, the owner/operator shall operate the gas turbines and HRSGs so that they comply with the following operational limits:

   a. Heat input limits (Higher Heating Value):

	Each Gas Turbine w/o Duct Burner	Each Gas Turbine w/Duct Burner
Hourly:	500 MM BTU/hr	639 MM BTU/hr
Daily:	11,342 MM BTU/day	15,336 MM BTU/day
Four Turbine/HRSG Power Trains combined:		18,215,000 MM BTU/year

   b. Only PUC-Quality natural gas (General Order 58-a) shall be used to fire the gas turbines and HRSGs. The total sulfur content of the natural gas shall not exceed 1.0 gr/100 scf.

   c. The owner/operator of the gas turbines and HRSGs shall demonstrate compliance with the daily and annual NOx and CO emission limits listed in part 22 by maintaining running mass emission totals based on CEM data. (Basis: Cumulative increase)

25. Monitoring Requirements: The owner/operator shall ensure that each gas turbine/HRSG power train complies with the following monitoring requirements:

   a. The gas turbine/HRSG exhaust stack shall be equipped with permanent fixtures to enable the collection of stack gas samples consistent with EPA test methods.

   b. The ammonia injection system shall be equipped with an operational ammonia flowmeter and injection pressure indicator accurate to plus or minus five percent at full scale and shall be calibrated at least once every twelve months.

   c. The gas turbine/HRSG exhaust stacks shall be equipped with continuously recording emissions monitor(s) for NOx, CO and O_2. Continuous emissions monitors shall comply with the requirements of 40 CFR Part 60, Appendices B and F, and 40 CFR Part 75, and shall be capable of monitoring concentrations and mass emissions during normal operating conditions and during gas turbine startups and shutdowns.

   d. The fuel heat input rate shall be continuously recorded using District-approved fuel flow meters along with quarterly fuel compositional analyses for the fuel's higher heating value (wet basis).

26. Source Testing/RATA: Within ninety (90) days of the startup of the gas turbines and HRSGs, and at a minimum on an annual basis thereafter, the owner/operator shall perform a relative accuracy test audit (RATA) on the CEMS in accordance with 40 CFR Part 60 Appendix B Performance Specifications and a source test shall be performed. Additional source testing may be required at the discretion of the District to address or ascertain compliance with the requirements of this permit. The written test results of the source tests

shall be provided to the District within thirty days after testing. A complete test protocol shall be submitted to the District no later than 30 days prior to testing, and notification to the District at least ten days prior to the actual date of testing shall be provided so that a District observer may be present. The source test protocol shall comply with the following: measurements of NOx, CO, POC, and stack gas oxygen content shall be conducted in accordance with ARB Test Method 100; measurements of PM_{10} shall be conducted in accordance with ARB Test Method 5; and measurements of ammonia shall be conducted in accordance with Bay Area Air Quality Management District test method ST-1B. Alternative test methods, and source testing scope, may also be used to address the source testing requirements of the permit if approved in advance by the District. The initial and annual source tests shall include those parameters specified in the approved test protocol, and shall at a minimum include the following:

a. NOx– ppmvd at 15% O2 and lb/MM BTU (as NO2)
b. Ammonia – ppmvd at 15% O2 (Exhaust)
c. CO – ppmvd at 15% O2 and lb/MM BTU (Exhaust)
d. POC – ppmvd at 15% O2 and lb/MM BTU (Exhaust)
e. PM_{10} – lb/hr (Exhaust)
f. SOx – lb/hr (Exhaust)
g. Natural gas consumption, fuel High Heating Value (HHV), and total fuel sulfur content
h. Turbine load in megawatts
i. Stack gas flow rate (DSCFM) calculated according to procedures in U.S. EPA Method 19
j. Exhaust gas temperature (°F)
k. Ammonia injection rate (lb/hr or moles/hr)
l. Water injection rate for each turbine at S-1, S-2, S-3, & S-4
(Basis: source test requirements & monitoring)

27. Within 60 days of start-up of the LECEF in combined-cycle configuration and on a semi-annual basis thereafter, the owner/operator shall conduct a District approved source test on exhaust points P-1, P-2, P-3, and P-4 while each Gas Turbine/HRSG power train is operating at maximum load to demonstrate compliance with the SAM emission limit specified in part 23. The owner/operator shall test for (as a minimum) SO_2, SO_3 and SAM. After acquiring one year of source test data on these units, the owner/operator may petition the District to switch to annual source testing if test variability is acceptably low as determined by the District. (Basis: PSD Avoidance, SAM Periodic Monitoring)

28. The owner/operator shall prepare a written quality assurance program must be established in accordance with 40 CFR Part 75, Appendix B and 40 CFR Part 60 Appendix F. (Basis: continuous emission monitoring)

29. The owner/operator shall comply with the applicable requirements of 40 CFR Part 60 Subpart GG, excluding sections 60.334(a) and 60.334(c)(1). The sulfur content of the natural gas fuel shall be monitored in accordance with the following custom schedule approved by the USEPA on August 14, 1987:
a. The sulfur content shall be measured twice per month for the first six months of operation.
b. If the results of the testing required by Part 26a are below 0.2% sulfur by weight, the sulfur content shall be measured quarterly for the next year of operation.
c. If the results of the testing required by Part 26b are below 0.2% sulfur by weight, the sulfur shall be measured semi-annually for the remainder of the permit term.
d. The nitrogen content of the fuel gas shall not be monitored in accordance with the custom schedule. (Basis: NSPS)

30. The owner/operator shall notify the District of any breakdown condition consistent with the District's breakdown regulations. (Basis: Regulation 1-208)

31. The owner/operator shall notify the District in writing in a timeframe consistent with the District's breakdown regulations following the correction of any breakdown condition. The breakdown condition shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the actions taken to restore normal operations. (Basis: Regulation 1-208)

32. <u>Recordkeeping</u>: The owner/operator shall maintain the following records. The format of the records is subject to District review and approval:

   a. hourly, daily, quarterly and annual quantity of fuel used and corresponding heat input rates
   b. the date and time of each occurrence, duration, and type of any startup, shutdown, or malfunction along with the resulting mass emissions during such time period
   c. emission measurements from all source testing, RATAs and fuel analyses
   d. daily, quarterly and annual hours of operation
   e. hourly records of NOx and CO emission concentrations and hourly ammonia injection rates and ammonia/NOx ratio
   f. for the continuous emissions monitoring system; performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor

   (Basis: record keeping)

33. The owner/operator shall maintain all records required by this permit for a minimum period of five years from the date of entry and shall make such records readily available for District inspection upon request. (Basis: record keeping)

34. <u>Reporting</u>: The owner/operator shall submit to the District a written report for each calendar quarter, within 30 days of the end of the quarter, which shall include all of the following items:

   a. Daily and quarterly fuel use and corresponding heat input rates
   b. Daily and quarterly mass emission rates for all criteria pollutants during normal operations and during other periods (startup/shutdown, breakdowns)
   c. Time intervals, date, and magnitude of excess emissions
   d. Nature and cause of the excess emission, and corrective actions taken
   e. Time and date of each period during which the CEM was inoperative, including zero and span checks, and the nature of system repairs and adjustments
   f. A negative declaration when no excess emissions occurred
   g. Results of quarterly fuel analyses for HHV and total sulfur content.

   (Basis: recordkeeping & reporting)

35. <u>Emission Offsets</u>: The owner/operator shall provide 7.3 tons of valid POC emission reduction credits prior to the issuance of the Authority to Construct. The owner/operator shall deliver the ERC certificates to the District Engineering Division at least ten days prior to the issuance of the authority to construct. (Basis: Offsets)

36. <u>District Operating Permit</u>: The owner/operator shall apply for and obtain all required operating permits from the District in accordance with the requirements of the District's rules and regulations. (Basis: Regulations 2-2 & 2-6)

37. Title IV and Title V Permits: The owner/operator must deliver applications for the Title IV and Title V permits to the District prior to first-fire of the turbines. The owner/operator must cause the acid rain monitors (Title IV) to be certified within 90 days of first-fire. (Basis: BAAQMD Regulation 2, Rules 6 & 7)

38. Deleted June 22, 2004.

39. The owner/operator shall insure that the S-5 Fire Pump Diesel Engine is fired exclusively on diesel fuel with a maximum sulfur content of 0.05% by weight. (Basis: TRMP, cumulative increase)

40. The owner/operator shall operate the S-5 Fire Pump Diesel Engine for no more than 100 hours per year or 45 minutes per day for the purpose of reliability testing and non-emergency operation. (Basis: cumulative increase, Regulation 9-8-231 & 9-8-330)

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

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:
    a. Total number of hours of operation for S-5
    b. Fuel usage at S-5
    (Basis: BACT)

43. The owner/operator shall operate the facility such that maximum calculated annual toxic air contaminant emissions (pursuant to part 48) from the gas turbines and HRSGs combined (S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10) do not exceed the following limits:

    6490 pounds of formaldehyde per year
    3000 pounds of acetaldehyde per year
    3.2 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year
    65.3 pounds of acrolein per year

    unless the following requirement is satisfied:
    The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and 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 result in a cancer risk of not more than 1.0 in one million, the District and CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Basis: TRMP)

44. To demonstrate compliance with Part 43, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions for the compounds specified in part 43 using the maximum heat input of 18,215,000 MM BTU/year and the highest emission factor (pound of pollutant per MM BTU) determined by any source test of the S-1, S-2, S-3 & S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs. If this calculation method results in an unrealistic mass emission rate the applicant may use an alternate calculation, subject to District approval. (Basis: TRMP)

45. Within 60 days of start-up of the Los Esteros Critical Energy Facility and on a biennial (once every two years) thereafter, the owner/operator shall conduct a District-approved source test at exhaust point P-1, P-2, P-3, or P-4 while the Gas Turbines are at maximum allowable operating rates to demonstrate compliance with Part 43. If three consecutive biennial source tests demonstrate that the annual emission rates for any of the compounds listed above calculated pursuant to part 43 are less than the BAAQMD Toxic Risk Management Policy trigger levels shown below, then the owner/operator may discontinue future testing for that pollutant.

Formaldehyde	<	132 lb/yr
Acetaldehyde	<	288 lb/yr
Specified PAHs	<	0.18 lb/yr
Acrolein	<	15.6 lb/yr

(Basis: BAAQMD 2-1-316, TRMP)

46. The owner/operator shall properly install and maintain the cooling towers to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 10,000 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (Basis: BACT, cumulative increase)

47. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the combined-cycle Los Esteros Critical Energy Facility, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in accordance with the manufacturer's design and specifications. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in part 46. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in part 46. (Basis: BACT, cumulative increase)

Summary and Determination

The proposed combined-cycle configuration of the Los Esteros Critical Energy Facility complies with all applicable federal, state and District rules and regulations. Therefore, the District recommends issuance of the Preliminary Determination of Compliance for the combined-cycle conversion of the Los Esteros Critical Energy Facility that is comprised of the following permitted pieces of equipment:

S-1 **Combustion Gas Turbine #1 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System**

S-2 Combustion Gas Turbine #2 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #3 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System.

S-4 Combustion Gas Turbine #4 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-5 Fire Pump Diesel Engine, John Deere Model JDFP-06WR, 290 bhp, 13.5 gal/hr

S-7 Heat Recovery Steam Generator #1, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-11 Six-Cell Cooling Tower, 73,000 gallons per minute

Pursuant to District Regulation 2-3-404, this revised Preliminary Determination of Compliance (PDOC) is subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. Consequently, a notice inviting written public comment on the proposed modifications to the LECEF will be published in a newspaper of general circulation within the District. All comments received during the 30-day public comment period will be considered and responses to those comments will be prepared.

Jack P. Broadbent
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Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109

Appendix A

Control Equipment Cost Summary

LECEF Phase 2
SCR Cost Comparison: 2.0 vs 2.5 ppm NOx

Turbine Model			GE LM6000		Cost
Turbine Output			50 MW		Increment
			2.5 ppm	2.0 ppm	
		Source			
Direct Capital Costs (DC)					
Purchased Equip. Cost (PE)					
Basic Equipment (A)		Deltak	$ 764,474	$ 794,474	$ 30,000
Ammonia injection skid and storage	0.00 x A	OAQPS	included	included	
Instrumentation	0.00 x A	OAQPS	included	included	
Taxes and freight	0.08 A x B	OAQPS	$ 61,158	$ 63,558	
PE Total			$ 825,632	$ 858,032	
Direct Installation Costs (DI)					
Foundation & supports	0.08 x PE	OAQPS	$ 66,051	$ 66,051	
Handling and erection	0.14 x PE	OAQPS	$ 115,588	$ 115,588	
Electrical	0.04 x PE	OAQPS	$ 33,025	$ 33,025	
Piping	0.02 x PE	OAQPS	$ 16,513	$ 16,513	
Insulation	0.01 x PE	OAQPS	$ 8,256	$ 8,256	
Painting	0.01 x PE	OAQPS	$ 8,256	$ 8,256	
DI Total			$ 247,690	$ 247,690	(included)
DC Total			$ 1,073,321	$ 1,105,721	
Indirect Costs (IC)					
Engineering:			$ 82,563		
Construction and field expenses			$ 41,282		
Contractor fees			$ 82,563		
Start-up			$ 16,513		
Performance testing			$ 8,256		
Contingencies			$ 24,769		
IC Total		Deltak	$ 255,946	$ 324,696	$ 68,750
Total Capital Investment (TCI = DC + IC)			$ 1,329,267	$ 1,430,417	
Direct Annual Costs (DAC)					
Operating Costs (O)	24 hrs/day, 7 days/wk, 50 wks/yr				
Operator	0.5 hrs/shift $25/hr	OAQPS	$ 13,125	$ 13,125	
Supervisor	15% of Operator	OAQPS	$ 1,969	$ 1,969	
Maintenance Costs (M)					
Labor	0.5 hrs/shift $25/hr	OAQPS	$ 13,125	$ 13,125	
Material	100% of labor cost	OAQPS	$ 13,125	$ 13,125	
Utility Costs					
Perf Loss	0.50%	Calpine (Note 1)		$ 35,325	$ 35,325
Electricity cost	0.06 ($/kwh) performance penalty	variable	$ 126,000	$ 126,000	
Catalyst replacement		Deltak	$ 123,239	$ 178,906	$ 55,667
Catalyst disposal			$ 4,621	$ 6,709	
Ammonia	$520/ton * tons NOx*17/46 * 1.05	Calpine	$ 59,904	$ 60,736	
NH3 injection skid			$ 11,591	$ 11,591	
Total DAC			$ 366,700	$ 460,611	
Indirect Annual Costs (IAC)					
Overhead	80% of O&M	BAAQMD	$ 33,075	$ 33,075	
Administrative	0.02 x TCI	BAAQMD	$ 26,585	$ 28,608	
Insurance	0.01 x TCI	BAAQMD	$ 13,293	$ 14,304	
Property tax	0.01 x TCI	BAAQMD	$ 13,293	$ 14,304	
Capital recovery	6.5% interest rate, 10 yr period 0.139 x TCI	BAAQMD	$ 184,768	$ 198,828	
Total IAC			$ 271,014	$ 289,120	
Total Annual Cost (DAC + IAC)			$ 637,713	$ 749,730	

Cost Increase	$ 112,017
Emissions Reduction	3.705
Cost Effectiveness	$ 30,234

Note 1: Basis for calculation of performance loss due to increased back pressure from additional catalyst required to meet 2.0 ppm.

a) Net Output reduced by 309 kW
b) Net Heat Rate increased by 10 Btu/kWh
c) Revised Net Output is 253,385 kW
d) Revised Net Heat Rate is 7439 Btu/kWh

Commercial impact estimate:

a) Output Impact = $29,700/year
b) Heat Rate Impact = $111,500/year
c) Net Impact = $141,200/year four turbines)