# Bay Area Air Quality Management District

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# Permit Evaluation
# and
# Statement of Basis
## For
## Renewal and Significant Revision
## of the

# MAJOR FACILITY REVIEW PERMIT

**for**

## Los Esteros Critical Energy Facility, LLC
## Facility #B3289

**Facility Address:**
800 Thomas Foon Chew Way
San Jose, CA 95134

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San Jose, CA 95134

January 2012

Application Engineer: Weyman Lee
Site Engineer: Brenda Cabral

Applications:
19302 (Renewal)
23956 (Significant Revision)

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# Title V Statement of Basis

## A. **Background**

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Title 70 of Volume 40 of the Code of Federal Regulations (CFR), and BAAQMD Regulation 2, Rule 6, Major Facility Review because it is a major facility as defined by BAAQMD Regulation 2-6-212, a Phase II Acid Rain facility as defined by BAAQMD Regulation 2-6-217, and a designated facility as defined in BAAQMD Regulation 2-6-204. It is an Acid Rain facility because it burns fossil fuel, serves a generator that is over 25 MW that is used to generate electricity for sale, and was built after November 15, 1990. It is a major facility because it has the "potential to emit," as defined by BAAQMD Regulation 2-6-218, more than 100 tons per year of ammonia. It is a designated facility because EPA has designated facilities that emit more than 100 tons per year of greenhouse gases measured on an absolute mass basis and more than 100,000 tons per year measured on a $CO_2e$ basis as subject to Title V permitting requirements, and its greenhouse gas emissions will exceed both of those applicability thresholds.

Major Facility Operating permits (Title V permits) must meet specifications contained in 40 CFR Part 70 as contained in BAAQMD Regulation 2, Rule 6. The permits must contain all applicable requirements (as defined in BAAQMD Regulation 2-6-202), monitoring requirements, recordkeeping requirements, and reporting requirements. The permit holders must submit reports of all monitoring at least every six months and compliance certifications at least every year.

In the Bay Area, state and District requirements are also applicable requirements and are included in the permit. These requirements can be federally enforceable or non-federally enforceable. All applicable requirements are contained in Sections I through VI of the permit.

Each facility in the Bay Area is assigned a facility identifier that consists of a letter and a 4-digit number. This identifier is also considered to be the identifier for the permit. The identifier for this facility is B3289.

This facility received its initial Title V permit on June 10, 2004. This Statement of Basis covers two applications. Application #19302 is for a permit renewal. Although the current permit expired on May 31, 2009, it continues in force until the District takes final action on the permit renewal. Application #23956 is for a significant revision of the Title V permit associated with the Phase II conversion project (to convert the plant from simple cycle to combined cycle) scheduled for completion in late 2012. Because the facility ceased operation in simple-cycle mode in January 2012 and will not be operated again until commissioning of the Phase II combined-cycle plant, the conditions governing operation in simple-cycle mode are no longer relevant and are being deleted and replaced with the requirements governing operation of the combined-cycle plant.

The standard sections of the permit have been upgraded to include new standard language used in all Title V permits. The proposed permit shows all changes to the permit in strikeout/underline format.

## B. Facility Description

The LECEF is an electric generating facility. It is located in the northern edge of the city of San Jose in Santa Clara County. The facility was online and selling electricity to the grid in March of 2003 as a simple-cycle facility consisting of four natural gas-fired turbines and rated at 180 MW.

In January 2012, LECEF ceased operation in simple-cycle mode as part of its conversion to a 320 MW combined-cycle power plant. In a combined-cycle operation, the waste heat in the turbine exhaust is recovered to make steam to turn a steam turbine and generate additional electric power, which increases the plant's overall efficiency. The conversion to combined-cycle operation entails the addition of four heat recovery steam generators (HRSGs), one steam turbine generator and one six-cell cooling tower. The old simple-cycle operation is referred to as "Phase I", and the new combined-cycle operation is referred to as "Phase II".

The Phase II combined-cycle plant will have higher heat input limits – meaning that the plant will be able to burn more fuel – due to the addition of duct burners in the HRSGs and an increase in the capacity of the turbines. This means that the annual emissions limits are higher for the combined-cycle plant than they were for the simple-cycle plant. But the combined-cycle plant will be more efficient, so emissions will be lower per MW of power generated than for the simple-cycle plant. In addition, there will be a reduction in annual POC and CO emissions limits because the POC and CO stack concentration limits are more stringent for the combined-cycle plant. Similarly, the ammonia slip limit for the combined-cycle plant has been reduced, resulting in lower ammonia emissions.

The Phase II combined-cycle facility will be required to keep emissions below the following hourly limits:

**Maximum Hourly Criteria Pollutant Emission Limits**

| **Pollutant:** | **$NO_x$** | **POC** | **CO** |
|---|---|---|---|
| Hourly Emission Limit | 2.0 ppmdv (1-hr average) | 2.0 ppmdv (1-hr average) | 1.0 ppmdv (1-hr average) |

In addition, the facility will be required to burn only low-sulfur pipeline quality natural gas, to use good combustion practices, and to install a high-efficiency inlet air filter to keep emissions fine particulate matter ($PM_{10}$) and Sulfur Dioxide ($SO_2$) as low as possible.

The Phase II combined-cycle facility will be subject to the following annual emission limits.

**Maximum Annual Criteria Pollutant Emission Limits**

| Pollutant: | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Annual Emission Limit | 95.21 | 12.31 | 44.24 | 53.44 | 6.45 |

The Phase II combined-cycle facility will be subject to the following limits on Toxic Air Contaminants (TACs).

**Maximum Annual TAC Emissions**

| HAP: | Ammonia | Formaldehyde | Hexane | Propylene | Toluene |
|---|---|---|---|---|---|
| Emission Limit (tons/year) | 56.9 | 3.2 | 2.3 | 6.8 | 1.2 |

The District issued an Authority to Construct (Application #3213) for the Phase II combined-cycle conversion project (LECEF II) on August 22, 2007.   The Authority to Construct (ATC), which expires after two years, was renewed in 2010 for an additional two years pursuant to District Regulation 2-1-407.1, which provides that an Authority to Construct may be renewed for an additional two years upon demonstrating that the project will meet current Best Available Control Technology (BACT) and offset requirements as defined in District Regulations 2-2-301, 2-2-302, and 2-2-303.  To meet current BACT standards, the emission limits for carbon monoxide, precursor organic compounds (POC), and ammonia (in the form of ammonia slip) were lowered.  In addition, the existing limits on the duration of and emissions from turbine startups startup and shutdown events were reduced.  The limit on total dissolved solids (TDS) content in the cooling water was lowered to 6,000 ppm.  The Final Determination of Compliance for the Authority to Construct issued in 2007 is included in Appendix C, and the Engineering Evaluation for the renewal of the Authority to Construct issued in 2010 is included in Appendix D.

The Phase II conversion project started construction on May 9, 2011.  The LECEF II ATC was renewed again for an additional two years in October, 2011 by satisfying the requirements of District Regulation 2-1-407.3, demonstrating substantial use through construction activities, acquisition of equipment, and awarding of an Engineering/Construction contract.

In January 2012, LECEF ceased operations as a simple-cycle plant and will not be operated again until commissioning of the Phase II combined-cycle conversion. Accordingly, the District is proposing in this Title V permit revision to delete those provisions only relevant to operation in simple-cycle mode and replace them with the conditions and terms governing operation of the combined cycle plant.

The District is required to provide information about the change in emissions for Title V renewals and significant revisions. The change in permitted emissions between Phase I and Phase II is shown below:

**Maximum Annual Facility Criteria Pollutant Emission Limits**

| Permit Limits (ton/yr) | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Phase I Simple-Cycle | 74.9 | 21.0 | 43.8 | 72.9 | 5.8 |
| Phase II Operation | 95.21 | 12.31 | 44.24 | 53.44 | 6.45 |
| Difference | 20.31 | -8.69 | 0.44 | -19.46 | 0.65 |

The next table compares the maximum allowable annual TAC (Toxic Air Contaminant) emissions for Phase I and Phase II:

**Comparison of Maximum Annual TAC Emissions**

| HAP Emissions (ton/yr) | Ammonia | Formaldehyde | Hexane | Propylene | Toluene |
|---|---|---|---|---|---|
| Phase I Simple-Cycle | 111 | 3.0 | 2.1 | 6.3 | 1.1 |
| Phase II Operation | 56.9 | 3.2 | 2.3 | 6.8 | 1.2 |
| Difference | -54.1 | 0.2 | 0.2 | 0.5 | 0.1 |

## C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order presented in the permit.

### I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. The section will contain a standard condition pertaining to Title IV (Acid Rain) requirements for fossil-fuel fired electrical generating facilities and the accidental release (40 CFR § 68) since these programs apply. Many of these conditions derive from 40 CFR § 70.6, Permit Content, which dictates certain standard conditions that must be placed in the permit. The language that the District has developed for many of these requirements has been adopted into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District's General Provisions and Permitting rules.

I. Standard Conditions

Changes to Standard Conditions 1.A:

- The amendment/adoption dates for the Administrative Requirements in I.A will be updated.
- BAAQMD Regulation 2, Rule 5 - New Source Review of Toxic Air Contaminants will be added.
- SIP Regulation 2, Rule 6 – Permits, Major Facility Review will be added.

Changes to Standard Conditions 1.B:

- The dates in Section I.B. will be updated.
- The words “to contain” in I.B.8 will be deleted.
- The reference in Standard Condition B.11 will be amended to add BAAQMD Regulation 2-6-409.20.
- The following language will be added as Standard Condition I.B.12:  "The permit holder is responsible for compliance, and certification of compliance, with all conditions of the permit, regardless whether it acts through employees, agents, contractors, or subcontractors.  (Regulation 2-6-307)."  The purpose is to reiterate that the Permit Holder is responsible for ensuring that all activities at the facility comply with all applicable requirements.

Changes to Standard Conditions 1.E:

- Reference to Regulation 3 will be deleted

Changes to Standard Conditions 1.F:

- The first reporting period requirements will be deleted.

Changes to Standard Conditions 1.L:

- Standard Condition L will be updated to allow permit holder to hold one sulfur dioxide allowance on March 1 (February 29$^{th}$ during a leap year) for each ton of sulfur dioxide emitted during the preceding year from January 1 through December 31.

## II. Equipment

This section of the permit lists all permitted or significant sources.  Each source is identified by an S and a number (e.g., S24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302.

Significant sources are those sources that have a potential to emit of more than 2 tons per year of a “regulated air pollutant” (as defined in BAAQMD Rule 2-6-222) or 400 pounds per year of a “hazardous air pollutant” (as defined in BAAQMD Rule 2-6-210).

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A-24).  If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an "S" number.  An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions.  If the primary function of a device is to control emissions, it is considered an abatement (or "A") device.  If the primary function of a device is a non-control function, the device is considered to be a source (or "S").

The equipment section is considered to be part of the facility description.  It contains information that is necessary for applicability determinations, such as fuel types, contents or sizes of tanks, etc.  This information is part of the factual basis of the permit.

Each of the permitted sources has previously been issued an authority to construct or a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. These permits are issued in accordance with state law and the District's regulations.  The capacities in the permitted sources table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

<u>Changes to permit</u>

- Source S6 Emergency Standby Generator was not installed and will be removed from Table II-A.
- The description of the S-5 Fire Pump Engine will be corrected to reflect the engine that was actually installed and is currently operating.
- Table II-A will be revised to delete descriptions only applicable to LECEF's operations as a simple cycle plant and to add the descriptions relevant to the combined cycle configuration.  S-1, S-2, S-3, and S-4, Gas Turbines, will have a higher capacity, and S-7, S-8, S-9, and S-10, Heat Recovery Steam Generators (HRSGs), and S-11 Cooling Tower will be added in Part 2.
- "dry, 3-hr average" will be added to the Limit or Efficiency column of Table II-B.
- Table II-B will be revised to delete descriptions of abatement equipment only relevant to operation as a simple cycle plant and add descriptions relevant to combined-cycle operation.  New oxidation catalyst and selective catalytic reduction systems (A-9, A-10, A-11, A-12, A-13, A-14, A-15, and A-16) will replace the existing systems (A-1, A-2, A-3, A-4, A-5, A-6, A-7, and A-8), and new lower emission concentration limits will apply.
- Table IIC, Significant Sources, will be created, and the existing cooling tower will be added to Table IIC.  The cooling tower will continue to operate after the Phase II conversion.  The cooling tower is a significant source because it emits more than 2 tons per year of particulate, a regulated air pollutant.

## III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a

District permit. If a generally applicable requirement applies specifically to a source that is permitted or significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

Unpermitted sources are exempt from normal District permits pursuant to an exemption in BAAQMD Regulation 2, Rule 1. They may, however, be specifically described in a Title V permit if they are considered "significant sources" as defined in BAAQMD Rule 2-6-239.

<u>Changes to Permit:</u>

Language will be added for unpermitted sources and for portable equipment that are considered significant pursuant to BAAQMD Rule 2-6-239.

A link to the text of the SIP-approved District standards on the EPA's website will be added.

Table III will be updated to reflect current regulation adoption dates and additional applicable regulations, and to add new regulations that have been adopted since the original Title V permit was issued.

- SIP Regulation 2, Rule 1 will be moved.
- BAAQMD Regulation 2, Rule 1-429, Federal Emissions Statement will be added.
- BAAQMD Regulation 2, Rule 2, New Source Review will be added.
- SIP Regulation 2, Rule 2, New Source Review will be added.
- BAAQMD Regulation 2, Rule 3, Power Plants will be added.
- BAAQMD Regulation 2, Rule 4, Emissions Banking will be added.
- SIP Regulation 2, Rule 4, Emissions Banking will be added.
- BAAQMD Regulation 2, Rule 5, New Source Review of Toxic Air Contaminants will be added.
- BAAQMD Regulation 2, Rule 6, Major Facility Review will be added.
- SIP Regulation 2, Rule 6, Major Facility Review will be added.
- BAAQMD Regulation 2, Rule 9, Interchangeable Emission Reduction Credits will be added.
- BAAQMD Regulation 3, Fees will be added.
- BAAQMD Regulation 4 and SIP Regulation 4, Air Pollution Episode Plan will be removed.
- BAAQMD Regulation 6, Rule 1, Particulate Matter, General Requirements will be added.
- SIP Regulation 6, Particulate Matter and Visible Emissions will be added.

- BAAQMD Regulation 8, Rule 2, Organic Compounds-Miscellaneous Operations will be added.
- BAAQMD Regulation 8, Rule 15, Organic Compounds-Emulsified and Liquid Asphalts will be added.
- BAAQMD Regulation 8, Rule 40, Organic Compounds-Aeration of Contaminated Soil and Removal of Underground Storage Tanks will be added.
- BAAQMD Regulation 8, Rule 47, Organic Compounds – Air Stripping and Soil Vapor Extraction Operations will be added.
- SIP Regulation 8, Rule 47, Organic Compounds – Aeration of Contaminated Soil and Removal of Underground Storage Tanks will be added.
- BAAQMD Regulation 9, Rule 1, Inorganic Gaseous Pollutants - Sulfur Dioxide will be added.
- SIP Regulation 9, Rule 1, Inorganic Gaseous Pollutants - Sulfur Dioxide will be added.
- BAAQMD Regulation 9, Rule 9, Inorganic Gaseous Pollutants - -Nitrogen Oxides from Stationary Gas Turbines will be added.
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants - -Nitrogen Oxides from Stationary Gas Turbines will be added.
- California Health and Safety Code Section 41750 et seq., Portable Equipment will be added.
- California Health and Safety Code Title 17, Section 93115 et seq., Airborne Toxic Control Measure for Stationary Compression Ignition Engines will be added.
- California Health and Safety Code Title 17, Section 93116, Airborne Toxic Control Measure for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater will be added.
- EPA Regulation 40 CFR 82, Protection of Stratospheric Ozone will be added.
- Subpart F, 40 CFR 82.156, Leak Repair will be added.
- Subpart F, 40 CFR 82.161, Certification of Technicians will be added.
- Subpart F, 40 CFR 82.166, Records of Refrigerant will be added.
- 40 CFR Part 82, Subpart H, Halon Emissions Reduction will be added.
- Title 40 Part 82, Subpart H, 82.270(b), Halon Prohibitions will be added.

## IV. Source-Specific Applicable Requirements

This section of the permit lists the applicable requirements that apply to permitted or significant sources. These applicable requirements are contained in tables that pertain to one or more sources that have the same requirements. The order of the requirements is:

- District Rules
- SIP Rules (if any) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in the California State Implementation Plan. SIP rules are "federally enforceable" and a "Y" (yes) indication will appear in the "Federally Enforceable" column. If the SIP rule is the

current District rule, separate citation of the SIP rule is not necessary and the "Federally Enforceable" column will have a "Y" for "yes". If the SIP rule is not the current District rule, the SIP rule or the necessary portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.

- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Section IV of the permit contains citations to all of the applicable requirements. The text of the requirements is found in the regulations, which are readily available on the District's or EPA's websites, or in the permit conditions, which are found in Section VI of the permit. All monitoring requirements are cited in Section IV. Section VII is a cross-reference between the limits and monitoring requirements. A discussion of monitoring is included in Section C.VII of this permit evaluation/statement of basis.

COMPLEX APPLICABILITY DETERMINATIONS:

**BAAQMD Regulation 4, Air Pollution Episode Plan**

This facility is not subject to District Regulation 4 and SIP Regulation 4 because the potential to emit is limited by permit conditions to less than 100 tons per year or more of air contaminants for which a California or federal ambient air quality standard is established pursuant to Regulation 4-301.

**40 CFR Part 64, Compliance Assurance Monitoring (CAM)**

The gas turbines are exempt from CAM requirements for $NO_x$ per 40 CFR Part 64.2(b)(iii) since the facility is subject to the acid rain permit program. The facility is subject to the Acid Rain program because it is a utility unit that serves a generator with a capacity greater than 25 MW in accordance with 40 CFR Part 72.6.

The gas turbine is exempt from CAM requirements for CO per 40 CFR Part 64.2(b)(vi) because the turbine has a continuous compliance method, the CO CEMs, that is specified by a part 70 permit.

**40 CFR Part 72, Acid Rain Program**

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The gas turbine is an affected unit subject to the program in accordance with 40 CFR Part 72, Subpart A, Section 72.6(a)(3)(i). The facility continues to meet 72.9 Standard Requirements which requires the submission of a complete acid rain permit application, the possession of a valid acid rain permit, meeting the monitoring requirements of part 75, and holding sufficient allowances, and comply with the acid rain $SO_2$ limit. The facility must hold sufficient $SO_2$ allowances by March 1 (February 29 of a leap year) of every year to offset each ton of $SO_2$ emitted for the previous calendar year. The facility is expected to comply with the excess emissions, recordkeeping and reporting requirements in 72.9(e) and 72.9(f).

Part 72, Subpart C, contains requirements for acid rain permit applications and compliance plans. The facility is expected to continue to meet these requirements.

Part 72, Subpart E, contains the requirements for the acid rain permit which must include all elements of a complete acid rain application.

**40 CFR Part 75, Continuous Emission Monitoring**

Part 75, Subpart A, contains the applicability criteria, compliance dates, and prohibitions. The emissions unit at the facility is subject to Part 72 and is therefore subject to Part 75. The $NO_x$ monitoring is subject to part 75 per 75.2(c). The facility is expected to continue to meet the compliance dates and prohibitions contained in part 75 Subpart A.

Part 75, Subpart B, contains specific monitoring provisions for each pollutant subject to part 75. The turbine at this facility is required to meet the $SO_2$, $NO_x$, and $CO_2$ monitoring requirements contained in 75.10(a)(1), 75.10(a)(2), 75.10(a)(3) Opacity monitoring under 75.10(a)(4) is not required for gas fired units in accordance with 75.14(c). 75.10(b) requires each CEM to meet equipment, installation, and performance specification in part 75, Appendix A, and quality assurance/quality control in Appendix B. 75.10(c) requires heat input rate monitoring to meet requirements contained in part 75 Appendix F. The facility is expected to continue to comply with the requirements contained in 75.10(b) and (c).

75.10(d) contains primary equipment hourly operating requirements that require the CEM to monitor emissions when the emissions unit combusts fuel except as specified in 75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §75.20. This section also contains requirements for calculating hourly averages from four 15-minute periods and validity of data and data substitution. Emission concentrations for a given hour are not considered valid unless it is based on four valid measurements. The data substitution requirements are contained in Subpart D. The facility is expected to continue to comply with the requirements contained in 75.10(d). 75.10(f) specifies minimum measurement capability requirement for CEMs and 75.10(g) contains the minimum recordkeeping and reporting requirements. The facility is expected to continue to meet 75.10(f) and (g).

75.11 contain specific provisions for $SO_2$ monitoring. 75.11(d)(2) allows the use of Appendix D to monitor $SO_2$ emissions from gas fired units. The facility monitors sulfur content of the natural gas to meet Part 75 $SO_2$ monitoring requirements.

75.12 contain specific provisions for $NO_x$ emission rates. The facility uses a $NO_x$ CEM and an $O_2$ monitor to meet this requirement.

75.13 contain $CO_2$ monitoring requirements. The facility monitors $CO_2$ in accordance with this section using the procedures in part 75, Appendix G.

75.14 contain opacity monitoring requirements. The facility is exempt from opacity monitoring under part 75 per 75.14(c).

Part 75, Subpart C, contains operation and maintenance requirements including certification and recertification of the CEM, quality assurance/quality control requirements, reference test methods, and out-of-control periods and adjustment for system bias. The facility is expected to continue to meet these requirements.

Part 75, Subpart D (75.30 through 75.36), contains Missing Data Substitution Procedures for $SO_2$, $NO_x$, flow rate, $CO_2$, and heat input procedures. The facility is expected to continue to meet these requirements.

Part 75, Subpart F, contains the recordkeeping requirements including the contents of a part 75 monitoring plan. This subpart requires the facility to record the operating time, heat input rate, and load for each emissions unit. Additionally, the facility must record emissions data for $SO_2$, $NO_x$, $CO_2$, and $O_2$ along with quality assurance/quality control information
.
Part 75, Subpart G, contains the reporting requirements for affected facilities subject to part 75. The facility is expected to continue to meet these requirements.

CHANGES TO PERMIT:

Table IV-A for S-1, S-2, S-3 & S-4, Combustion Turbines, will be updated to reflect new regulation adoption dates and by adding the following rules and standards. Sources S-7, S-8, S-9 & S-10, Heat Recovery Steam Generators, will be added as applicable sources to reflect conversion of LECEP to a combined cycle configuration.

- BAAQMD Regulation 1-107, Combination of Emissions, will apply after the Phase II conversion.
- BAAQMD Regulation 1-520 (1&8), Continuous Emission Monitoring
- BAAQMD Regulation 6, Rule 1, citations
- BAAQMD Regulation 6, Rule 1, Particulate Matter and Visible Emissions: 6-1-304 Tube Cleaning will apply after the Phase II conversion.
- BAAQMD Regulation 6, Rule 1, Particulate Matter and Visible Emissions: 6-1-310.3 Heat Transfer Operation will apply after the Phase II conversion.
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-301 Ringelmann Number 1 Limitation
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-304 Tube Cleaning will apply after the Phase II conversion.
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-305 Visible Particles
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-310 Particulate Weight Limitation
- BAAQMD Regulation 6, Particulate Matter and Visible Emissions: 6-1-310.3 Heat Transfer Operation will apply after the Phase II conversion

- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-401 Appearance of Emissions
- BAAQMD Regulation 9, Rule 3, Inorganic Gaseous Pollutants-Nitrogen Oxides from Heat Transfer Operations: 9-3-303, New or Modified Heat Transfer Operation Limits will apply after the Phase II conversion.
- BAAQMD Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-301.1.3, Emission Limits- Turbines Rated ≥ 10 MW w/SCR
- BAAQMD Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-301.2, Emission Limits - Turbine heat input rated > 250 – 500 MMBtu/hr
- BAAQMD Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-401 Certification, Efficiency
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-113, Exemption – Inspection/Maintenance
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-114, Exemption – Start-Up/Shutdown
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-301, Emission Limits, General
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-301.3, Emission Limits – Turbine Limits Rated ≥ 10 MW w/SCR
- SIP Regulation 9, Rule 9, Inorganic Gaseous Pollutants-Nitrogen Oxides from Stationary Gas Turbines: 9-9-501 Monitoring and recordkeeping requirements
- The provisions of NSPS, Subpart GG, will be deleted because the sources will be subject to NSPS, Subpart KKKK since the conversion project is defined as a modification in accordance with 40 CFR 60.14.
- 40 CFR 60 Subpart KKKK, provisions will be added and will apply after the Phase II conversion.
- 40 CFR 60, Appendix B, provisions will be added and will apply after the Phase II conversion.
- Federal Regulations: 40 CFR Part 72, Title IV Acid Rain permit requirements: More detail has been provided.
- Federal Regulations: 40 CFR Part 75, Continuous Emissions Monitoring requirements:  More detail has been provided.
- Permit Condition #19610, which applied to the simple cycle operation will be deleted and replaced by Permit Condition #23688.

Table IV-B for S-5 diesel fire pump will be updated by adding the following rules and standards.

- BAAQMD Regulation 6, Rule 1 citations
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-303 Ringelmann Number 2 Limitation
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-305 Visible Particles

- BAAQMD Regulation 6, Particulate Matter and Visible Emissions: 6-310 Particulate Weight Limitation will be renamed as a "SIP" regulation
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-401 Appearance of Emissions
- BAAQMD Regulation 9-8-110.5, Limited exemption for Emergency Standby Engines
- BAAQMD Regulation 9-8-330.1, 330.2, 330.3, Hours of Operation
- BAAQMD Regulation 9-8-502 Recordkeeping.
- BAAQMD Regulation 9-8-502.1 Monthly records of usage
- Federal Regulations 40 CFR Part 63, Subpart A National Emissions for Hazardous Air Pollutants (NESHAPs) General Requirements
- Federal Regulations 40 CFR Part 63, Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustions Engines (RICE) requirements. S-5 fire pump is powered by a compression ignition (ci), diesel fired, 300 HP engine. It is not subject to emission and operating limitations, fuel requirements, performance testing, initial compliance, and notification requirements in this subpart. The engine is subject to the following requirements: (1) maintenance procedures of Table 2d, Part 4; (2) general maintenance for safety and to minimize emissions; (3) limited operation for non-emergency maintenance checks and testing; and (4) continuous compliance and recordkeeping.
- CCR, Title 17, Section 93115 ATCM for Stationary Compression Ignition Engines

  The District has reviewed all reporting requirement according to Airborne Toxic Control Measure (ATCM) section 93115.10 (a)(3) and (5) for the stationary CI engine. The engine meets all the requirements for reporting.
- Permit Condition 19610, parts 39 through 42 have been deleted and replaced by Permit Condition 23688, parts 39 through 42.

Table IV-C for S-6 will be deleted as this source was not installed.

A new Table IV-C will be added for S-11 Six Cell Cooling Tower that is part of the Phase II conversion.

## V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10 which provides that a major facility review permit shall contain the following information and provisions:

"409.10 A schedule of compliance containing the following elements:

10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;

10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and

10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan

> shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted."

Since the District has not determined that the facility is out of compliance with an applicable requirement, the schedule of compliance for this permit contains only sections 2-6-409.10.1 and 2-6-409.10.2.

## VI. Permit Conditions

During the Title V permit development, the District has reviewed the existing permit conditions, deleted the obsolete conditions, and, as appropriate, revised the conditions for clarity and enforceability. Each permit condition is identified with a unique numerical identifier, up to five digits.

When necessary to meet Title V requirements, additional monitoring, recordkeeping, or reporting has been added to the permit.

All changes to existing permit conditions are clearly shown in "strike-out/underline" format in the proposed permit. When the permit is issued, all 'strike-out" language will be deleted and all "underline" language will be retained, subject to consideration of comments received.

The existing permit conditions are derived from previously issued District Authorities to Construct (A/C) or Permits to Operate (P/O). Permit conditions may also be imposed or revised as part of the annual review of the facility by the District pursuant to California Health and Safety Code (H&SC) § 42301(e), through a variance pursuant to H&SC § 42350 et seq., an order of abatement pursuant to H&SC § 42450 et seq., or as an administrative revision initiated by District staff. After issuance of the Title V permit, permit conditions will be revised using the procedures in Regulation 2, Rule 6, Major Facility Review.

The regulatory basis is listed following each condition. The regulatory basis may be a rule or regulation. The District is also using the following terms for regulatory basis:

- BACT: This term is used for a condition imposed by the Air Pollution Control Officer (APCO) to ensure compliance with the Best Available Control Technology in Regulation 2-2-301.
- Cumulative Increase: This term is used for a condition imposed by the APCO, which limits a source's operation to the operation described in the permit application pursuant to BAAQMD Regulation 2-1-403.
- Offsets: This term is used for a condition imposed by the APCO to ensure compliance with the use of offsets for the permitting of a source or with the banking of emissions from a source pursuant to Regulation 2, Rules 2 and 4.

- PSD:  This term is used for a condition imposed by the APCO to ensure compliance with a Prevention of Significant Deterioration permit issued pursuant to Regulation 2, Rule 2.
- Regulation 2, Rule 5:  This term is used for a condition imposed by the APCO to ensure compliance with limits based on Regulation 2, Rule 5 New Source Review of Toxic Air Contaminants.

Changes to permit:

All changes to existing permit conditions are clearly shown in "strike-out/underline" format in the proposed permit.  When the permit is issued, all 'strike-out" language will be deleted and all "underline" language will be retained, subject to consideration of comments received.

This section deletes Condition #19610, which only applied to the simple cycle plant, and replaces it with Condition #23688, which applies to the Phase II Combined Cycle conversion of LECEF.

The construction of the Phase II combined cycle conversion has begun and the conversion is expected to be completed in 2013.  Because LECEF has ceased operation in simple-cycled mode, Condition #19160 is no longer applicable.  Permit Condition #23688 is consistent with the CEC Conditions of Certification.

## VII. Applicable Limits and Compliance Monitoring Requirements

This section of the permit is a summary of numerical limits and related monitoring requirements for each source.  The summary includes a citation for each monitoring requirement, frequency of monitoring, and type of monitoring.  The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

The District has reviewed the limits for which there is no monitoring required and has determined that additional monitoring is not required.  The District has also examined the monitoring for other limits and has determined that the monitoring is adequate to provide a reasonable assurance of compliance.  Calculations for potential to emit are provided in the discussion when no monitoring is proposed due to the size of a source.

Monitoring decisions are typically the result of a balancing of several different factors including: 1) the likelihood of a violation given the characteristics of normal operation, 2) degree of variability in the operation and in the control device, if there is one, 3) the potential severity of impact of an undetected violation, 4) the technical feasibility and probative value of indicator monitoring, 5) the economic feasibility of indicator monitoring, and 6) whether there is some other factor, such as a different regulatory restriction applicable to the same operation, that also provides some assurance of compliance with the limit in question.

These factors are the same as those historically applied by the District in developing monitoring for applicable requirements**.** It follows that, although Title V calls for a re-examination of all monitoring**,** there is a presumption that these factors have been appropriately balanced and incorporated in the District's prior rule development and/or permit issuance. It is possible that, where a rule or permit requirement has historically had no monitoring associated with it, no monitoring may still be appropriate in the Title V permit if, for instance, there is little likelihood of a violation**.** Compliance behavior and associated costs of compliance are determined in part by the frequency and nature of associated monitoring requirements. As a result, the District will generally revise the nature or frequency of monitoring only when it can support a conclusion that existing monitoring is inadequate**.**

Changes

The Heat Recovery Steam Generators, S-7, S-8, S-9, and S-10 will be added to Table VII-A. Requirements that apply only to the simple cycle operation are being deleted in Table VII-A and will be replaced by requirements that apply to the combined cycle conversion.

Table VII-C will be added for S-11 Cooling Tower. The requirements in this Table will apply after the Phase II Conversion.

**$PM_{10}$ Sources**

| S# & Description | Emission Limit Citation | Federally Enforceable Emission Limit | Monitoring |
|---|---|---|---|
| S-1, S-2, S-3, S-4, & S-5, Combustion Gas Turbines, Diesel Fire Pump and Cooling Tower (2-cell), S-7, S-8, S-9, S-10, HRSGs, S-11 Six Cell Cooling Tower | BAAQMD Regulation 6-1-310 | 0.15 grain/dscf | None |
| S-1, S-2, S-3, S-4, & S-5, Combustion Gas Turbines, Diesel Fire Pump and Cooling Tower (2-cell), S-7, S-8, S-9, S-10, HRSGs S-11 Six Cell Cooling Tower | SIP Regulation 6-310 | 0.15 grain/dscf | None |

**$PM_{10}$ Sources**

| S# & Description | Emission Limit Citation | Federally Enforceable Emission Limit | Monitoring |
|---|---|---|---|
| S-1, S-2, S-3, S-4, & S-5 Combustion Gas Turbines, Diesel Fire Pump and Cooling Tower S-7, S-8, S-9, S-10 HRSGs S-11 Six Cell Cooling Tower | BAAQMD Regulation 6-1-301 | Ringelmann 1.0 for more than 3 min/hr | None |
| S-1, S-2, S-3, S-4, & S-5 Combustion Gas Turbines, Diesel Fire Pump and Cooling Tower S-7, S-8, S-9, S-10 HRSGs S-11 Six Cell Cooling Tower | SIP Regulation 6-301 | Ringelmann 1.0 for more than 3 min/hr | None |
| S-1, S-2, S-3,& S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10, HRSGs | BAAQMD condition #23688 part 22 | 38.5 tons/year PM10 for all turbines combined including startup and shutdown. | Annual source test, calculations |

**PM Discussion:**
BAAQMD Regulation 6, Rule 1 “Particulate Matter General Requirements”

<u>Visible Emissions</u>
BAAQMD Regulation 6-1-301 limits visible emissions to no darker than 1.0 on the Ringelmann Chart (except for periods or aggregate periods less than 3 minutes in any hour).  Visible emissions are normally not associated with combustion of gaseous fuels, such as natural gas.  The combustion turbines (Sources S-1, S-2, S-3, & S-4) and the HRSGs (Sources S-7, S-8, S-9, & S-10) burn natural gas exclusively; therefore, per the EPA's June 24, 1999 agreement with CAPCOA and ARB titled "Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", no monitoring is required to assure compliance with this limit for this source.

EPA's June 24, 1999 agreement with CAPCOA and ARB entitled "Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP" states that no monitoring will be required for opacity for diesel standby and emergency reciprocating engines if California diesel or other low-sulfur fuels are used.  The reason is that the use of low-sulfur fuels reduces particulates. Also, these engines are used infrequently and therefore, are not large sources of particulate emissions. Because the S-5 Fire Pump Diesel Engine will utilize "California" diesel fuel, no monitoring is required to ensure compliance with the visible emissions limitation of Regulation 6-1-303.1.

The two Cooling Towers are not expected to emit visible particulate emissions. Therefore, monitoring is not required to ensure compliance with Regulation 6-1-301 for this source

Particulate Weight Limitation

BAAQMD Regulation 6-1-310 limits filterable particulate (FP) emissions from any source to 0.15 grains per dry standard cubic foot (gr/dscf) of exhaust volume. Section 310.3 limits filterable particulate emissions from "heat transfer operations" to 0.15 gr/dscf @ 6% $O_2$. These are the "grain loading" standards.

Exceedances of the grain loading standards are normally not associated with combustion of gaseous fuels, such as natural gas. Sources S-1, S-2, S-3, & S-4, S-7, S-8, S-9, and S-10 burn natural gas exclusively, therefore, per the EPA's July 2001 agreement with CAPCOA and ARB entitled "CAPCOA/CARB/EPA Region IX Recommended Periodic Monitoring for Generally Applicable Grain Loading Standards in the SIP: Combustion Sources: Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", no monitoring is required to assure compliance with this limit for these sources.

The grain loading from the Cooling Towers are expected to be much less than 0.15 grains per dscf. Permit Condition #23688 Part 46 require a daily test for the TDS level in the cooling water, and an initial source test (thereafter on the 5th and 15th years) for the cooling drift rate, to ensure that the S-11 Cooling Tower will emit less than 0.15 grains per dscf. The smaller exempt two cell tower is much smaller than the six cell S-11 Cooling Tower and monitoring will not be required.

EPA's July 2001 agreement with CAPCOA and ARB entitled "CAPCOA/CARB/EPA Region IX Recommended Periodic Monitoring for Generally Applicable Grain Loading Standards in the SIP: Combustion Sources: Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", proposes the following monitoring for the grain loading standard for non-utility distillate-oil-fueled emergency piston-type IC Engines: Maintain records of all engine usage (such as time or fuel meter readings) and maintenance. S-5 Fire Pump Diesel Engine is subject to such monitoring.

Maximum Annual Mass Emissions Limit

The combined cycle plant will be subject to BAAQMD Permit Condition #23688, part 22, which will limit $PM_{10}$ emissions from all power trains (S-1, S-2, S-3 & S-4 gas turbines and S-7, S-8, S-9, & S-10 HRSGs) to 38.5 tons/yr. Part 22 requires the facility to demonstrate compliance with this emissions limit by continuously monitoring fuel usage and calculating total annual $PM_{10}$ emissions by multiplying fuel usage by an emissions factor determined during annual source test. Using an emissions factor in this manner is an appropriate method for determining compliance with the annual $PM_{10}$ limit because $PM_{10}$ emissions do not depend on the functioning of any add-on control device and are therefore not expected to fluctuate greatly.[1] To the contrary, $PM_{10}$ emissions are influenced primarily by the sulfur content of the natural gas the plant is burning and the combustion conditions under which the fuel is burned. The facility will be required to burn only low-sulfur pipeline quality natural gas, and will be require to sample the fuel and to analyze its sulfur content at least once per month to monitor compliance with this requirement. The facility will also be required to maintain good combustion practices, and compliance will be ensured by the continuous monitoring of CO emissions as a surrogate for good combustion practices. If good combustion conditions are not maintained, CO emissions will rise and will be detected by facility operators who can correct the situation to bring CO emissions back within permit limits, which will also address any increase in $PM_{10}$ emissions from a lack of good combustion practices. For these reasons, $PM_{10}$ emission rates are not expected to deviate by any significant amount from the emissions factor determined by annual source testing, and so the use of fuel consumption rate times an emissions factor is an appropriate method to determine compliance with the annual $PM_{10}$ emission limit. This is the standard approach that regulatory agencies use for monitoring annual $PM_{10}$ emissions from natural gas combustion sources.[2]

## $SO_2$ Sources

[1] Emission rates always fluctuate somewhat from test to test, as there is a natural variability in the emissions performance of any equipment over time. $PM_{10}$ emissions rates vary far less than those for other pollutants that are controlled by add-on control technology, however, since the add-on control device could fail to work properly, which could result in greatly increased emissions. For example, an SCR system, an add-on control technology used to limit NOx emissions, can have an effectiveness of over 90% in reducing NOx emissions. If the device should fail, NOx emissions could accordingly increase by as much as 10 times. The inherent variability in $PM_{10}$ emission rates is far smaller, as there is no add-on control technology involved. For example, in 24 source tests conducted on the turbines at the LECEF Phase I simple-cycle plant, the maximum emissions rate never even got to as much as 2 times the average emission rate seen in the tests. This relative lack of fluctuation in $PM_{10}$ emission rates is one important reason why it is appropriate to use an emission factor based on an annual source test to determine annual $PM_{10}$ emissions.

[2] It is also worth noting that historical source testing of the turbines at this facility showed an average $PM_{10}$ emission rate of 1.22 pounds per hour, which is well below the average rate of 2.2 pounds per hour that was used in determining the 38.5 maximum annual $PM_{10}$ emissions limit. Although the combined-cycle operation will have the ability to burn an increased amount of fuel, this is not expected to change $PM_{10}$ emissions significantly compared to the simple-cycle operation. Certainly, it is not expected to increase the 1.22 pound-per-hour historical average above the 2.2 pound-per-hour rate used in determining the annual emission limit. Annual $PM_{10}$ emissions are therefore expected to be well within the 38.5 tons/yr permit limit, and compliance will be ensured through a calculation of the annual emissions rate as measured by multiplying fuel usage times an emissions factor determined during an annual source test.

| S# & Description | Emission Limit Citation | Federally Enforceable Emission Limit | Monitoring |
|---|---|---|---|
| S-1, S-2, S-3, S-4, & S-5 Combustion Gas Turbines, Diesel Fire Pump S-7, S-8, S-9, S-10 HRSGs | BAAQMD 9-1-301 | Ground level concentrations of SO2 shall not exceed: 0.5 ppm for 3 consecutive minutes AND 0.25 ppm averaged over 60 consecutive minutes AND 0.05 ppm averaged over 24 hours | None |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD 9-1-302 | 300 ppm (dry) | Fuel Gas Total sulfur content analysis |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | NSPS Subpart KKKK 40 CFR 60.4330(a)(2) | 0.060 lb/SO2/MMbtu | None |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 (combined cycle) | 6.43 tons/calendar year for All turbines combined including startup and shutdown of turbines except during commissioning | Periodic Sulfur Analysis, Calculations Annual Source Test |
| S-5 Diesel Fire Pump | BAAQMD 9-1-304 | Sulfur content of fuel < 0.5% by weight | Fuel certification by vendor |

**$SO_2$ Discussion:**

<u>BAAQMD Regulation 9-1-301</u>

Area monitoring to demonstrate compliance with the ground level SO2 concentration requirements of Regulation 9-1-301 is at the discretion of the APCO (per BAAQMD Regulation 9-1-501). This facility does not have equipment that emits large amounts of SO2 and therefore is not required to have ground level monitoring by the APCO.

All facility combustion sources are subject to the SO2 emission limitations in District Regulation 9, Rule 1 (ground-level concentration and emission point concentration). In EPA's June 24, 1999 agreement with CAPCOA and ARB, "Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", EPA has agreed that natural-gas-fired combustion sources do not need additional monitoring to verify compliance with Regulation 9, Rule 1, since violations of the regulation are unlikely. Therefore, no monitoring is necessary for this requirement.

The S-5 Fire Pump Diesel Engine will utilize “California” diesel fuel that contains no more than 15 ppm sulfur. Therefore, monitoring is not required.

NSPS 40 CFR 60.4330(a)(2)
This federal regulation, which applies after the Phase II conversion, requires that the total sulfur content of fuel used at the gas turbines be less than 0.060 lb SO2/MMBtu. As described above, the natural gas used at S-1, S-2, S-3 and S-4 is pipeline quality. PG&E Gas Rule 21, Section C specifies a maximum total sulfur content of less than 1.0 grains of sulfur per 100 scf, which is equivalent to 0.0028 lb SO2/MMBtu[3]. The maximum grain loading in pipeline natural gas is much lower than 0.060 lb SO2/MMBtu. Therefore, no monitoring is required to ensure compliance with this limit.

Maximum Annual Mass Emissions Limits

The combined cycle plant will be subject to the BAAQMD Permit Condition #23688 Parts 22 which limits SO2 emissions from all power trains (S-1, S-2, S-3 & S-4 gas turbines and S-7, S-8, S-9, & S-10 HRSGs) to 6.43 tons/yr. As with $PM_{10}$, compliance will be determined by calculating annual $SO_2$ emissions as measured by annual fuel usage times an emissions factor derived from an annual source test. $SO_2$ emissions are similar to $PM_{10}$ emissions in that they do not depend on any add-on control device and are influenced primarily by the amount of sulfur in the natural gas that is burned. SO2 emissions therefore do not fluctuate greatly,[4] and so it is appropriate to monitor emissions my measuring fuel usage and multiplying it by an emissions factor determined through an annual source test. In addition, compliance with the low-sulfur-fuel requirement will be monitored through monthly fuel sulfur content sampling an analysis. This monitoring requirement will have an additional benefit in ensuring that the annual SO2 emissions limit is complied with. For all of these reasons, using fuel use data in conjunction with an emissions factor determined though an annual source test is an appropriate manner to ensure compliance with the annual $SO_2$ emissions limit.

| **NOx Sources** | | | |
|---|---|---|---|
| **S# & Description** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD 9-9-301.1.3 | 9 ppmv @ 15% O2, dry | CEM and annual source test |

[3] The worst case sulfur emission factor (based on 1 gr/dscf sulfur content) is calculated as follows:
(1 gr/100scf)($10^6$ Btu/MM Btu)(2 lb $SO_2$/lb S)/[(7000 gr/lb)(1030 Btu/scf)] = **0.0028 lb $SO_2$/MM Btu**

[4] In the 24 source tests conducted on the LECEF Phase I facility, the maximum $SO_2$ emissions were never more than 1.5 times the average. Both the average and the maximum of these 24 source tests (0.169 lb/hr and 0.269 lb/hr, respectively) were comfortably below the rates used to establish the annual $SO_2$ emissions limit, and so there is no reason to expect that the facility's emissions will not be able to comply with that limit.

| **NOx Sources** | | | |
|---|---|---|---|
| **S# & Description** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD 9-9-301.2 | 9 ppmv @ 15% O2, dry Or 0.43 lbs/MW-hr | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD 9-9-301.2 | 0.43 lbs/MW hr or 9 ppmv @ 15% O2, dry | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | SIP 9-9-301.3 | 9 ppmv @ 15% O2, dry | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | NSPS Subpart KKKK 40 CFR 60.4320(a) | 25 ppmv @ 15% O2, dry | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 10 | 1464 lb/day and 102 lb/hr for all turbines combined during commissioning, including startup and shutdown of turbine without catalyst | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 10 | 1464 lb/day and 61 lb/hr for all turbines combined during commissioning, including startup and shutdown of turbine with catalyst | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 19a | 2 ppmv @ 15% O2, dry, 1-hr average except during turbine startup or shutdown | CEM |

| NOx Sources | | | |
|---|---|---|---|
| S# & Description | Emission Limit Citation | Federally Enforceable Emission Limit | Monitoring |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 252.4 lb/day for each turbine including startup and shutdown | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 22 | 1009.6 lb/day (as NO2) for all turbines combined, including startup and shutdown | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 (combined cycle) | 94.1 tons per year (as NO2) for all turbines combined, except during startup or shutdown | CEM |

**NOx Discussion:**

BAAQMD Regulation 9 Rule 9

The turbines are subject to the $NO_x$ emission limitations in District Regulation 9, Rule 9 (Monitoring and Recordkeeping Requirements). This facility has a stationary gas turbine with a heat input rate greater than 150 MMBtu/hr and operates more than 4000 hours in a 36-month period. Therefore it is required to have Continuous Emission Monitoring (CEM) and to complete an annual source (BAAQMD Regulation 9-9-301).

The CEM is used to demonstrate compliance with the $NO_x$ concentration permit limits on a continuous basis. An annual relative accuracy test audit (RATA) is required (Permit Condition #23688, part 26) on the $NO_x$ CEM to ensure accuracy. $NO_x$ mass emissions are calculated using $NO_x$ and $O_2$ CEM data, and the fuel heat input rate (from fuel flow meter). The District has determined that no additional monitoring is required.

This level of monitoring is also required for the combined cycle plant, and is deemed to be sufficient to determine compliance with NOx emissions requirements.

| **CO Sources** | | | |
|---|---|---|---|
| **S# & Description** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 10 (combined cycle) | 1056 lb/day and 88 lb/hr for all turbines combined during commissioning, including startup and shutdown of turbine without catalyst | CEM and annual source test |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 10 | 984 lb/day and 41 lb/hr for all turbines combined during commissioning, including startup and shutdown of turbine with catalyst | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD Condition #23688 Part 19c | 2 ppmv @ 15% $O_2$, dry 1-hr average except during turbine startup or shutdown | CEM and annual source test |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 175.6 lb/day for each turbine including startup and shutdown | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 702.4 lb/day for all turbines combined, including startup and shutdown | CEM |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 94.1 tons per year for all turbines combined, including startup and shutdown | CEM |

**CO Discussion:**

BAAQMD Regulation 9 Rule 7

The turbines are subject to the CO emission limitations in District Regulation 9, Rule 7 (Monitoring and Recordkeeping Requirements).  The turbines are also subject to Condition #23688, part 19c, which establishes a CO emissions limit of 2.0 ppmv @ 15% O2 (1-hr avg.).  The turbines have the potential to emit large amounts of CO. Therefore, they are required to have a CO CEM and an annual source test.

The CEM is used to demonstrate compliance with the CO concentration permit limits on a continuous basis.  An annual relative accuracy test audit (RATA) is required (Permit Condition 23688, part #26) on the CO CEM to ensure accuracy.  CO mass emissions are calculated using CO and $O_2$ CEM data, and the fuel heat input rate (from fuel flow meter).  The District has determined that no additional monitoring is required.

**POC Sources**

| S# & Description | Emission Limit Citation | Federally Enforceable Emission Limit | Monitoring |
|---|---|---|---|
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 10 | 114 lb/day for all turbines combined during commissioning and including startup and shutdown of turbines w/ catalyst | Source Test, records & calculation |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 10 (combined cycle) | 288 lb/day for all turbines combined during commissioning and including startup and shutdown of turbines w/o catalyst | Source Test, records & calculation |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 19d | 1 ppmv @ 15% O2, dry, 1-hr average except during turbine startup or shutdown | Source Test |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 20.2 lb/day for each turbine including startup and shutdown | Source Test, records & calculation |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 22 | 80.8 lb/day for all turbines combined, including startup and shutdown | Source Test, records & calculation |

| POC Sources | | | |
|---|---|---|---|
| **S# & Description** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines<br>S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 22 | 12.3 tons/year for all turbines combined including startup and shutdown. | Source Test, records & calculation |

**POC Discussion:**

Maximum Short-Term Concentration and Maximum Daily and Annual Mass Emissions
Emissions of Precursor Organic Compounds (POC) from the LECEF Phase II facility will be limited to 1 ppmvd (1-hr avg.), 20.2 pounds per day from each turbine/HRSG power train, 80.8 pounds per day from all 4 turbine/HRSG power trains combined, and 12.3 tons per year from all 4 turbine/HRSG power trains combined. It is not technically feasible to implement continuous emissions monitoring for these POC limits, as there are currently no available monitors that can measure POC emissions at the very low levels that will be emitted from this equipment (below 1.0 ppm). Instead, ongoing compliance will be assured by the fact that source testing has shown that under good combustion conditions and with a properly-functioning oxidation catalyst, POC emissions will be well below the 1.0 ppm limit. Specifically, source testing at the previous Phase I facility showed that POC emissions averaged 0.374 ppm. Moreover, good combustion conditions and the proper functioning of the oxidation catalyst will be assured on a continuous basis by continuous monitoring of CO emissions, which – like POC emissions – depend on combustion conditions and the functioning of the oxidation catalyst. If any problems arise with combustion conditions or with the oxidation catalyst that could cause POC emissions to rise and exceed permit limits, any such problems will be detected in real time through continuous monitoring of the CO emissions, and the facility will be required to address them and return the equipment to normal operating conditions. Finally, POC emissions will also be source-tested annually to ensure that under normal operating conditions (i.e., under good combustion conditions and with the properly functioning oxidation catalyst), emissions are still within the 1.0 ppm limit. This annual source testing will provide continued assurance that the facility is maintaining POC emissions from the turbine/HRSG power trains in compliance with applicable permit limits.

| **$NH_3$ Sources** | | | |
|---|---|---|---|
| **S# & Description** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 19b | 5 ppmv @ 15% O2, dry, averaged over 3 hrs except during turbine startup or shutdown | $NH_3$ flow meter |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 19b | 5 ppmv @ 15% O2, dry, averaged over 3 hrs except during turbine startup or shutdown | Source Test |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 104 lb/day for each turbine including startup and shutdown | Ammonia flow meter |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688, part 22 | 416 lb/day for all turbines combined, including startup and shutdown | Ammonia flow meter |
| S-1, S-2, S-3, S-4, Combustion Gas Turbines S-7, S-8, S-9, S-10 HRSGs | BAAQMD condition #23688 part 22 | 56.9 tons/year for all turbines combined including startup and shutdown. | Source test |

**$NH_3$ Discussion:**

Maximum Short-Term Concentration and Maximum Daily and Annual Mass Emissions
The facility will have the potential to emit ammonia ($NH_3$) from the SCR systems used to abate NOx emissions in the exhaust stream from the gas turbines/HRSGs. The ammonia is used to react with the NOx and convert it to elemental nitrogen and water. Some of the ammonia may not be fully reacted, however, and may end up being emitted in the exhaust from the SCR systems. Such emissions are called “ammonia slip”.

Ammonia slip emissions from the facility’s SCR systems will be subject to the following limits: 5 ppmvd @ 15% O2, averaged over any 3-hour period; 104 pounds per day per turbine and 416 pounds per day for all 4 turbines combined; and 56.9 tons per year in total from all 4 turbines combined. $NH_3$ emissions will be monitored by continuously measuring the amount of NOx and ammonia being introduced into the SCR system and then determining the amount of $NH_3$ that is being reacted with the NOx and the amount that may be left over to be emitted as ammonia slip. The maximum ratio of $NH_3$ to NOx that will keep emissions below the 5 ppm permit limit will be established through source testing once the Phase II combined-cycle facility is constructed. The facility will then be required to ensure continuous compliance by maintaining the $NH_3$/NOx ratio below that maximum level. Re-testing will be required annually thereafter to track $NH_3$/NOx ratios, and the maximum allowable ratio will be adjusted if necessary according to these source test results to ensure that a proper ratio is maintained to establish compliance. This type of emissions monitoring for ammonia slip is the standard mechanism for ensuring compliance at SCR systems at facilities of this type.

| **HAP Sources**<br>S-1, S-2, S-3, S-4,<br>Combustion Gas Turbines<br>S-7, S-8, S-9, S-10,<br>Heat Recovery Steam Boiler | | | |
|---|---|---|---|
| **HAP** | **Emission Limit Citation** | **Federally Enforceable Emission Limit** | **Monitoring** |
| Formaldehyde | BAAQMD condition #23688 part 43 (combined cycle) | 6490 pounds/year for all turbines combined | Source Test at Startup and biennial thereafter |
| Acetaldehyde | BAAQMD condition #23688 part 43 (combined cycle) | 3000 pounds/year for all turbines combined | Source Test at Startup and biennial thereafter |
| Specified PAH's | BAAQMD condition #23688 part 43 (combined cycle | 3.2 pounds/year for all turbines combined | Source Test at Startup and biennial thereafter |
| Acrolein | BAAQMD condition #23688 part 43 (combined cycle | 65.3 pounds/year for all turbines combined | Source Test at Startup and biennial thereafter |

**Hazardous Air Pollutant (HAP) Discussion:**
<u>BAAQMD Regulation 2, Rule 5</u>
Emissions of formaldehyde, acetaldehyde, specified PAH's, and acrolein are source tested within 60 days of startup and biennially thereafter. If three consecutive biennial tests demonstrate that the emissions are less than the respective threshold levels in BAAQMD condition #23688, part 49, future testing for that pollutant may be discontinued. Continuous Emission Monitoring (CEM) is not available for HAPs.

The combined cycle facility will have the same monitoring requirements for HAPs.

**Changes to permit**:
A note will be added at the beginning of Section VII to clarify that this section is a summary of the applicable limits that have associated monitoring requirements, and that

in the case of a conflict between Sections I-VI and Section VII, the preceding sections take precedence.

Tables in Section VII will be updated to reflect new regulations that have been adopted since the original Title V permit was issued.  Requirements for the Phase II combined cycle plant have been added and requirements only applicable to simple-cycle operation will be deleted.

Table VII-A will be updated by adding the following rules and standards:

- BAAQMD Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbine: 9-9-301.1.3 Emission Limits, General
- BAAQMD Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbine: 9-9-301.2 Emission Limits, General
- SIP Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbine: 9-9-301.3 Emission Limits, General
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-310 Particulate Weight Limitation
- Under NOx limits, Monitoring Requirement Citation for NOx, will be updated for NSPS requirements.
- Under NOx limits, Subpart KKKK will be added for the combined cycle operation.
- Under NOx limits, Condition #23688, Parts 10, 19a, & 22 will be added.
- Under CO limits, Condition #23688, Parts 10, 19c, & 22 will be added.
- Under SO2 limits, Monitoring Requirement Citation for SO2, will be updated for NSPS requirements.
- Under SO2 limits, Subpart KKKK will be added.
- Under SO2 limits, Condition #23688, Part 22, will be added.
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-301 Ringelmann No.1 Limitation
- SIP Regulation 6, Particulate Matter and Visible Emissions: 6-310 Grain Loading
- Under PM10 limits, Condition #23688, Part 22, will be added
- Under POC limits, Condition #23688, Parts 10, 19d, & 22 will be added .
- Under NH3 limits, Condition #23688, Parts 19b & 22 will be added.
- Formaldehyde, acetaldehyde, PAHs, and acrolein requirements will be added.
- Under Operating Limitations, requirements from BAAQMD Condition #23688 will be added.

Table VII-B will be changed as follows:

- Remove Sulfur content requirement of fuel <0.05% by weight
- Update Condition number references
- Add SIP Regulation 6-310 FP and 6-302 opacity requirements
- Add Subpart ZZZZ requirements

Table VII-C, Applicable Limits and Monitoring Requirements, for S-11, Cooling Tower, will be added.

Former Table VII-C, Applicable Limits and Monitoring Requirements, for natural gas fired engine generator, was deleted because S-6 Engine was not installed:

## VIII. Test Methods

This section of the permit lists test methods that are associated with standards in District or other rules. It is included only for reference. In most cases, the test methods in the rules are source test methods that can be used to determine compliance but are not required on an ongoing basis. They are not applicable requirements.

If a rule or permit condition requires ongoing testing, the requirement will also appear in Section IV of the permit.

<u>Changes to permit:</u>
Table VII-B will be changed as follows:

- Remove Regulation 9-7 references
- Add requirements for Regulation 9-9-301.2
- Add requirements for NSPS, Subpart KKKK
- Add requirements for NSPS, 40 CFR 60.8
- Add Permit Condition 23688, Part 19, requirements for combined cycle operation

## IX. Acid Rain

SO2 ALLOWANCE ALLOCATIONS

| | Year | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| | **allowances under Table 2 of 40 CFR Part 73** | **None** | **None** | **None** | **None** | **None** |
| **Combustion Turbines And future HRSGs** | **NOx Limit** | **; unit is not subject to the NOx requirements from 40 CFR Part 76 as this unit is not capable of firing on coal.** | | | | |

ADDITION TO COMMENTS, NOTES AND JUSTIFICATIONS

Pursuant to 40 CFR Part 72.6(a)(3)(i), S-1 is considered a new utility unit and is subject to the acid rain permit requirements of 72.9(a).

S-1, S-2, S-3, and S-4, Gas Turbines, are not listed in table-2 of 40 CFR Part 73, therefore, the operator did not receive initial SO2 allowances under the Acid Rain program.

S-1, S-2, S-3, and S-4, Gas Turbines, do not qualify for a new unit exemption pursuant to 40 CFR 72.7 (b)(1) since each serves a generator with a nameplate capacity greater than 25 MW.

## X. Permit Shield

The District rules allow two types of permit shields. The permit shield types are defined as follows: (1) A provision in a major facility review permit explaining that specific federally enforceable regulations and standards do not apply to a source or group of sources, or (2) A provision in a major facility review permit explaining that specific federally enforceable applicable requirements for monitoring, recordkeeping and/or reporting are subsumed because other applicable requirements for monitoring, recordkeeping, and reporting in the permit will assure compliance with all emission limits.

The second type of permit shield is allowed by EPA's White Paper 2 for Improved Implementation of the Part 70 Operating Permits Program. The District uses the second type of permit shield for all streamlining of monitoring, recordkeeping, and reporting requirements in Title V permits. The District's program does not allow other types of streamlining in Title V permits.

This facility does not have permit shields.

Changes to permit:
In the initial Title V permit, Los Esteros Critical Energy Facility applied for and received a permit shield for subsumed requirements in Table X B-1. This shield no longer applies and will be deleted from the permit because 40 CFR 60 Subpart GG will not apply to the facility after the construction. Therefore this shield is not necessary.

## XI. Revision History

This section details the revision history of the facility's Title V permit.

Changes to permit:

The renewal permit contains the following updated information regarding the application for renewal:

| Date | Action | Details |
|---|---|---|
| June 10, 2004 | Final Permit | Initial Permit |
| | Permit Renewal | Application 19302 – Title V Permit Renewal. |
| | Significant Revision | Application 23956 - Revisions associated with the Phase II Conversion project to change the LECEF from a simple cycle to a combined cycle plant. |

## XII. Glossary

This section contains terms that may be unfamiliar to the general public or EPA.

## XIII. Title IV Permit Application

The Acid Rain permit application for the facility is part of the Title V permit and is included here.

### D. Alternate Operating Scenarios

No alternate operating scenario has been requested for this facility.

## E. Compliance Status

An inter-office memorandum from the Director of Compliance and Enforcement, to the Director of Permit Services, presents a review of the compliance record of Los Esteros (Site #: B3289). The Compliance and Enforcement Division staff has reviewed the records for Los Esteros for the period between January 1, 2007, through January 9, 2012. This review was initiated as part of the District evaluation of an application for a Title V permit. During the period subject to review, activities known to the District include:

- There were nine Notices of Violation issued during this review period. Some of these Notices of Violation were issued for emissions in excess of applicable limits, while others were issued for non-emissions-related violations such as late reporting of information. The District has reviewed each of the violations involved and found that each violation was promptly addressed, is not a current or ongoing violation, and is not part of a pattern of recurring or repeated violations.
- The District did not receive any alleged complaints.
- The facility is not operating under a Variance or an Order of Abatement from the District Board.

The owner certified that all equipment was operating in compliance on December 28, 2008. No ongoing non-compliance issues have been identified to date. The District therefore has not found any reason to include any additional compliance-related conditions in the Title V permit.

# APPENDIX A

## Glossary

**ACT**
Federal Clean Air Act

**APCO**
Air Pollution Control Officer

**ARB**
Air Resources Board

**BAAQMD**
Bay Area Air Quality Management District

**BACT**
Best Available Control Technology

**Basis**
The rule or regulation that gives the District authority to impose requirements

**CAA**
The federal Clean Air Act

**CAAQS**
California Ambient Air Quality Standards

**CAPCOA**
California Air Pollution Control Officers Association

**CEQA**
California Environmental Quality Act

**CFR**
The Code of Federal Regulations - 40 CFR contains the implementing regulations for federal environmental statutes such as the Clean Air Act. Parts 50-99 of 40 CFR contain the requirements for air pollution programs.

**CO**
Carbon Monoxide

**Cumulative Increase**
The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Cumulative increase is used to determine whether threshold-based requirements are triggered.

**District**
The Bay Area Air Quality Management District

**dscf**
Dry Standard Cubic Feet

**EPA**
The federal Environmental Protection Agency.

**Excluded**
Not subject to any District regulations.

**Federally Enforceable, FE**
All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

**FP**
Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

**HAP**
Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

**Major Facility**
A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as determined by the EPA administrator.

**MFR**
Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

**MOP**
The District's Manual of Procedures.

**NAAQS**
National Ambient Air Quality Standards

**NESHAPS**
National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

**NMHC**
Non-methane Hydrocarbons (Same as NMOC)

**NMOC**
Non-methane Organic Compounds (Same as NMHC)

**NOx**
Oxides of nitrogen.

**NSPS**
Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

**NSR**
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

**Offset Requirement**
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NOx, PM10, and SO2.

**Phase II Acid Rain Facility**
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

**POC**
Precursor Organic Compounds

**PM**
Particulate Matter

**PM10**
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

**PSD**
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

**SIP**
State Implementation Plan. State and District programs and regulations approved by EPA and developed in order to attain the National Air Ambient Quality Standards. Mandated by Title I of the Act.

**SO2**
Sulfur dioxide

**THC**
Total Hydrocarbons (NMHC + Methane)

**Title V**
Title V of the federal Clean Air Act. Requires a federally enforceable operating permit program for major and certain other facilities.

**TOC**
Total Organic Compounds (NMOC + Methane, Same as THC)

**TPH**
Total Petroleum Hydrocarbons

**TSP**
Total Suspended Particulate

**VOC**
Volatile Organic Compounds

**Units of Measure:**

| | | |
|---|---|---|
| bhp | = | brake-horsepower |
| btu | = | British Thermal Unit |
| cfm | = | cubic feet per minute |
| g | = | grams |
| gal | = | gallon |
| gpm | = | gallons per minute |
| hp | = | horsepower |
| hr | = | hour |
| lb | = | pound |
| in | = | inches |
| max | = | maximum |
| $m^2$ | = | square meter |
| min | = | minute |
| mm | = | million |
| MMbtu | = | million btu |
| MMcf | = | million cubic feet |
| ppmv | = | parts per million, by volume |
| ppmw | = | parts per million, by weight |
| psia | = | pounds per square inch, absolute |
| psig | = | pounds per square inch, gauge |
| scfm | = | standard cubic feet per minute |
| yr | = | year |

# APPENDIX B

## BAAQMD Compliance Report

**COMPLIANCE & ENFORCEMENT DIVISION**

**Inter-Office Memorandum**

Gin Kwan **January 9, 2012**

TO: ~~JOHN CHILADAKIS~~ – DIRECTOR OF ENGINEERING 1/13/12

FROM: BRIAN BATEMAN – DIRECTOR OF ENFORCEMENT

SUBJECT: REVIEW OF COMPLIANCE RECORD OF:

**LOS ESTEROS CRITICAL ENERGY FACILITY;**
**SITE # B3289**

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## Background

This review was initiated as part of the District evaluation of an application by Los Esteros Critical Energy Facility (Los Esteros) for a Title V Permit Renewal. It is standard practice of the Compliance and Enforcement Division to undertake a compliance record review in advance of a renewal of a Title V Permit. The purpose of this review is to assure that any non-compliance problems identified during the prior five-year permit term have been adequately addressed, or, if non-compliance persists, that a schedule of compliance is properly incorporated into the Title V permit compliance schedule. In addition, the review checks for patterns of recurring violation that may be addressed by additional permit terms. Finally, the review is intended to recommend, if necessary, any additional permit conditions and limitations to improve compliance.

Los Esteros is a power generation facility using natural-gas to fire four Gas Turbines with Water Injection Systems. A Continuous Monitoring System is in place for the water-to-fuel ratios necessary for compliance with the permit condition. Los Esteros also has a standby diesel engine.

## Compliance Review

Compliance records were reviewed for the time period from January 1, 2007 through January 9, 2012. The results of this review are summarized as follows.

**1. Violation History**

Staff reviewed Los Esteros Annual Compliance Certifications and found no ongoing non-compliance and no recurring pattern of violations.

Staff also reviewed the District compliance records for the review period. During this period, Los Esteros activities known to the District include:

REVIEW OF COMPLIANCE RECORD OF:
**FACILITY NAME – SITE #**
Date
Page 2 of 5

District-issued nine Notice of Violations (NOV's):

| NOV# | Regulation | Date Occur | # of Days | Comments | Disposition |
|---|---|---|---|---|---|
| A48979 | 2-6-307 | 9/8/06 | 1 | Ammonia emissions exceeded 10 Parts Per Million, Volumetric Dry (ppmvd) | Resolved |
| A48980 | 2-6-307 | 9/6/06 | 1 | Ammonia emissions exceeded 10 ppmvd | Resolved |
| A48984 | 2-6-307 & 1-522.7 | 3/6/06 | 1 | Late reporting Reportable Compliance Activity (RCA): 04v26 | Resolved |
| A48985 | 1-522.7 | 1/14/05 | 1 | Late reporting RCAs: 04V27 & 04V28 | Resolved |
| A48992 | 2-6-307 | 7/25/07 | 1 | Ammonia emissions exceeded in source test | Resolved |
| A48993 | 2-6-307 | 7/15/07 | 1 | Carbon Monoxide (CO) limits exceeded Denied RCA: 05B27 | Resolved |
| A48994 | 1-522.7 | 7/19/07 | 1 | Late reporting RCA: 05B28 | Resolved |
| A48995 | 2-6-307 & 1-523.3 | 8/11/05 | 1 | Late reporting RCAs: 05C45-05C49 | Resolved |
| A49996 | 2-6-307 & 1-523.3 | 7/2907 & 5/16/07 | 1 | Late reporting RCAs: 05B40 & 05B41 | Resolved |

NOV#A48979, A48980, and A48992 were issued for failure to meet the District permit condition #19610, Part 19(b): Ammonia emissions from the gas turbine shall not exceed 10 ppmvd @ 15% $O_2$ except during periods of startup and shutdown as defined in this permit.

NOV#A48984 was issued for failure to meet the District permit condition #19610, Part 19(a): The Oxides of Nitrogen (NOx) emissions from the gas turbine shall not exceed 5.0 ppmvd @ 15% Oxygen ($O_2$) (3-hour rolling average), except during periods of startup and shutdown as defined in this permit. NOV was also issued for late reporting of RCA #04v26. Regulation 1-522.7 states: Any indicated excess of any emission standard to which the source is required to conform, as indicated by the monitor, shall be reported to the Air Pollution Control Officer (APCO) within 96 hours after such occurrence. The report shall include the nature, extent, and cause.

NOV#A48985 was issued for late reporting of RCAs 04V27 & 04V28 under Regulation 1-522.7.

NOV#A48993 was issued for failure to meet the District permit condition #19610, Part 19(c): CO emissions from the gas turbine shall not exceed 4 ppmvd @ 15% $O_2$ (3-hour rolling average), except during periods of startup and shutdown as defined in this permit.

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NOV#A48994 was issued for exceeding 96 hours for reporting excess emissions under RCA 05B28.

NOV#A48995 and A48996 were issued for late reporting of excess emissions under RCAs 05B40, 05B41, and 05C45-05C49. Regulation 1-523.3 states: Any violation of permit conditions of District regulations to which the source is required to confirm, as indicated by the monitor, shall be reported to the APCO within 96 hours after such occurrence. The report shall include the nature, extent, and cause.

### 2. Complaint History

The District received no air pollution complaints alleging Los Esteros Critical Energy as the source.

### 3. Reportable Compliance Activity

Reportable Compliance Activity (RCA), also known as "Episode" reporting, is the reporting of compliance activities involving a facility as outlined in District Regulations and State Law. Reporting covers breakdown requests, indicated monitor excesses, pressure relief device releases, inoperative monitor reports and flare monitoring.

Within the review period, the District received 25 notifications for RCA's. Three NOV's for four violations were issued as a result of these RCA's.

The District received 25 notifications for RCA's.

| Episode | Date Occur | # of Days | Comments | Disposition |
|---|---|---|---|---|
| 05A45 | 5/16/07 | 1 | Continuous Emission Monitors (CEMs) malfunction | No action |
| 05A46 | 5/16/07 | 1 | Associated to Breakdown (BD) #05A45 | No action |
| 05B07 | 7/5/07 | 1 | NOx analyzer failed | Relief Granted |
| 05B09 | 7/5/07 | 1 | Associated to BD#05B07 | No action |
| 05B11 | 7/5/07 | 1 | NOx analyzer fault | No action |
| 05B12 | 7/6/07 | 1 | NOx analyzer fault | No action |
| 05B27 | 7/15/07 | 1 | Operating fuel gas compressor tripped | Denied/NOV#A48993 |
| 05B28 | 7/15/07 | 1 | Assoc. to BD#05B27 | Denied/NOV#A48994 |
| 05B29 | 7/23/07 | 1 | Fault of CEMS Data Acquisition and Handling Software (DAHS) system | No action |
| 05B30 | 7/24/07 | 1 | Degradation of Selective catalytic reduction (SCR) Catalyst | No action |
| 05B36 | 7/25/07 | 1 | Degradation of SCR Catalyst | No action |
| 05B40 | 5/16/07 | 1 | Degradation of SCR Catalyst | Denied/NOV#A48996 |
| 05B41 | 6/29/07 | 1 | Degradation of SCR Catalyst | Denied/NOV#A48996 |

| | | | | |
|---|---|---|---|---|
| 05B57 | 8/14/07 | 1 | O2 stack monitor malfunction | No action |
| 05B58 | 8/15/07 | 1 | O2 stack monitor malfunction | No action |
| 05B71 | 8/20/07 | 1 | Power supply failure | No action |
| 05B73 | 8/21/07 | 1 | Inlet NO analyzer failure | No action |
| 05D77 | 1/22/08 | 1 | Fuel gas compressor breakdown | Granted |
| 05D78 | 1/22/08 | 1 | Associated to BD#05D77 | No action |
| 05F89 | 5/18/08 | 1 | Inlet NOx analyzer indicated ammonia slip | No action |
| 05K24 | 12/17/08 | 1 | Malfunction of NOx analyzer | No action |
| 05K25 | 12/17/08 | 1 | Associated to BD#05K24 | No action |
| 05U17 | 6/5/10 | 1 | Fuel flow transmitter indicated lower than usual temperature | Relief Granted |
| 05U18 | 6/5/10 | 1 | Assoc. to BD#05U17 | No action |
| 05U31 | 6/5/10 | 1 | Fuel flow transmitter indicated lower than usual temperature (Inoperative monitor) | No action |

**4. Enforcement Agreements, Variances, or Abatement Orders**

There were no enforcement agreements, variances, or abatement orders for Los Esteros review period.

## Conclusion

Following its review of all available facility and District compliance records from January 1, 2007 through January 9, 2012, the District's Compliance and Enforcement Division has determined that Los Esteros Critical Energy Facility was in intermittent compliance from the initial permit period through the present. However, Los Esteros Critical Energy has demonstrated no evidence of ongoing noncompliance and no recurring pattern of violations that would warrant consideration of a Title V permit compliance schedule for this facility.

Based on this review, the District has concluded that no schedule of compliance or change in permit terms is necessary beyond what is already contained in the facility's current Title V permit.

# APPENDIX C

# Engineering Evaluation for 2007 Phase II ATC

# Final
# Determination of Compliance

**Los Esteros Critical Energy Facility**
Plant 13289

Combined-Cycle Conversion (Phase 2)

Bay Area Air Quality Management District
Application 8859

June 28, 2005

Dennis Jang, P.E.
Senior Air Quality Engineer

**FINAL DETERMINATION OF COMPLIANCE**

**LOS ESTEROS CRITICAL ENERGY FACILITY**

**Application 8859**
**Plant 13289**

## Background

This is the Final Determination of Compliance (FDOC) 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.

**The initial Preliminary Determination of Compliance for the "combined-cycle" LECEF was issued on September 28, 2004. A revised PDOC was issued on March**

**14, 2005.  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 in the revised PDOC.**

**Typical Operating Scenarios:**

As a municipal power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

*Base Load* The facility would be operated at maximum continuous output for as many hours per year as scheduled by load dispatch. During high ambient temperature periods or other periods of high demand, duct firing may be used to increase the plant output at the desired load to meet increased SVP utility system demand.

*Peak Load* The facility can provide additional output by duct firing the HRSG and provide additional steam to the steam turbine.

*Load Following* The facility would be operated to meet variable SVP load requirements. The generation would be adjusted periodically to the load demand by raising or lowering the output of the combustion turbines.

*Ancillary Services* The facility may operate in response to rapid California Independent System Operator (CAISO)-commanded load changes due to sale of spinning reserves or automatic load changes commanded due to sale of regulation services (Automatic Generation Control (AGC)).

*Partial Shutdown* At certain times of any given day and any given year, it may be necessary to shut down one gas turbine/HRSG power train. This mode of operation could generally be expected during late evening and early morning hours, when system demand may be low.

*Full Shutdown* This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect or market conditions.

Because several of these potential operating scenarios may result in rapid load changes that would lead to inefficient operation of the gas turbine combustors, excursion language will be included with the NOx emission concentration limit that allows for limited NOx emissions in excess of 2.0 ppmv but less than 5.0 ppmv. The number of hours allowed for these excursions is proportional to the number allowed for the recently permitted Pico Power Project.

**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$^o$F to 1100$^o$F. With combined-cycle gas turbines, exhaust heat is removed with a HRSG, resulting in stack gas temperatures ranging from 550$^o$F to 750$^o$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$^o$F to 1050$^o$F. Vanadium pentoxide catalysts are effective in the temperature range of 550$^o$F to 750$^o$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$^o$F without HRSG duct burner firing
- 1,250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29$^o$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$^o$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$^o$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.

**<u>Combined-Cycle Configuration (Phase 2):</u>**

- **<u>Nitrogen Oxides (NOx as $NO_2$)</u>**

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 hourly 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)
= 0.01981 lb CO/MM BTU

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

(0.01981 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:

(0.01981 lb CO/MM BTU)(639 MM BTU/hr) = **12.66 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$^{o}$F without HRSG duct burner firing
- 1250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29$^{o}$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/$10^6$)(35.4 lb/hr)
= 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.

<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 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.

The Las Vegas Cogeneration Facility in Clark County, Nevada is equipped with 4 GE LM6000 gas turbines operating in combined-cycle mode and abated by SCR systems and oxidation catalysts. These units are permitted at emission limits of 2.0 ppmv NOx and 4.0 ppmv CO. However, a review of the NOx CEM data shows that the units are not consistently meeting the NOx concentration limit, excluding gas turbine start-ups, shutdowns, and CEM calibration periods. For example, the Unit #2 turbine exceeded the NOx limit for 16 hours during the 4$^{th}$ quarter of 2004, when Unit #2 operated for 2,060 hours, excluding start-ups, shutdowns, and CEM calibration periods. Units #3, #4, and #5 exceeded the NOx limit for 10, 16, and 7 hours, respectively, during the 4$^{th}$ quarter of 2004. It is unclear whether those "excess" hours would have been considered excursions due to transient conditions. However, it is clear that the Las Vegas turbines are not consistently meeting the 2.0 ppmv NOx limit. Based upon its review of existing data, the District has determined that a NOx limit of 2 ppm has not yet been achieved in practice. And it certainly had not been achieved in practice by February, 2004, when this application was deemed to be complete as defined by Regulation 2-1-201.

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 that may occur under the typical operating scenarios discussed on page 3 of this FDOC. 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% $O_2$. This will be discussed in greater detail in 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)**

The LM 6000 Sprint gas turbines at LECEF utilize conventional combustors with water injection and SCR for NOx control. For this equipment, NOx and CO emissions are inversely related. 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 level of CO emissions that the equipment can achieve is therefore generally dependent upon the NOx emission level that is required. Therefore, lowering NOx emissions will tend to increase peak CO emissions.

There is no achieved-in-practice BACT level for CO emissions for this type of equipment that is also subject to a 2.0 ppm NOx limit. 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. However, 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 Dry Low-NOx (DLN) combustors. Because this facility uses different equipment and is subject to a higher NOx emission limit, it can achieve lower CO emissions than LECEF will be able to, and is therefore not a comparable facility for purposes of a CO BACT achieved-in-practice determination. BACT Guideline 89.1.6 is therefore not applicable to the combined-cycle LECEF that will be subject to a NOx limit of 2.0 ppm.

Moreover, the District is not aware of any other facilities that are comparable to LECEF operating with a NOx limit of 2.0 ppm that could serve as a basis for an achieved-in-practice BACT determination. 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 analysis 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 Las Vegas Cogeneration project in Clark County, Nevada, uses the same equipment as LECEF and is permitted at 2.0 ppm NOx. The District has reviewed CEM data from that facility, however, and has found that it has not been consistently meeting its 2.0 ppm NOx limitation. As a result, this facility is not comparable to LECEF for purposes of an achieved-in-practice BACT determination for CO emissions.

The Sithe Mystic facility located in Everett, Massachusetts is equipped with four Mitsubishi 501G gas turbines with a nominal output of 250 MW each. They are equipped with dry Low-NOx combustors and are abated by SCR and oxidation catalysts. These units are subject to a NOx emission limit of 2 ppmv and CO emission limit of 2 ppmv. Because these turbines are approximately five times larger than the turbines employed at LECEF, they are not considered comparable for the purposes of an achieved-in-practice BACT determination.

Finally, the Pico Power Project uses similar equipment, and is permitted at a NOx limit of 2.0 ppm and a CO limit of 6.0 ppm. This project has only just recently come on-line, however, and there is insufficient data regarding its CO emissions performance to be able to make a determination that it has in fact achieved that limit in practice. This project cannot therefore be used to support an achieved-in-practice BACT determination.

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. The District's current cost-effectiveness criteria for CO is zero dollars per ton of CO reduced, which means that the District has determined that additional reduction of CO does not justify any additional cost. This application involves an existing source, with existing control equipment. BACT therefore requires a CO emission limit that is technologically feasible for the facility to meet on a consistent basis, without having to incur any additional costs for additional control equipment.

The applicant has provided some limited data regarding the correlation between decreasing NOx emissions and corresponding increases in CO emissions. Specifically, the applicant has looked at CO performance while increasing the water injection rate at the combustors in order to reduce NOx emissions. The data shows that 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 the permitted level of 2.0 ppmv. The CO emissions limit must therefore allow for additional CO emissions to ensure that compliance with the 2.0 ppmv NOx limit is achievable. The District has determined that a 9.0 ppmv limit will provide a reasonable and appropriate margin of compliance to ensure that the facility does not violate its permit conditions, given the limited nature of the available data on which to make this BACT determination and the inexact nature of the correlation between lowering NOx emissions and increasing CO emissions. The District is not aware of any data showing that a CO limit of less than 9.0 ppmv will be achievable, and therefore cannot make a determination that BACT requires a limit less than that level.

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, increasing the short-term CO emission concentration limit from the 4.0 ppmv achieved-in-practice BACT level for higher NOx levels to 9.0 ppmv for a 2.0 NOx limit is acceptable given the corresponding air quality benefit that will be realized from the lower NOx emissions. 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.

The District has also 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.

## BACT for S-11 Six-Cell Cooling Tower

### 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 | 20.8 | 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 | 7.500 | 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 | 7.500 | 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. However, the applicant is submitting 13.370 tons per year of $SO_2$ offsets to partially mitigate $PM_{10}$ emission increases from the facility pursuant to CEC requirements under CEQA.

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.

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 19.022 tons per year of POC, 283.749 tons per year of NOx, and 76.270 tons per year of $SO_2$ will be re-issued as new banking certificates and returned to Calpine.

## Table 9 Emission Reduction Credits Identified by Calpine as of June 2, 2005 (tons/yr)

| Current Owner | Certificate Number | Pollutant Quantity (tpy) | | | Origin, Location | Date Banked |
|---|---|---|---|---|---|---|
| | | POC | NOx | $SO_2$ | | |
| Calpine | 856 | 26.522 | 0 | 0 | Myers Container, San Pablo | 4/23/02 |
| LECEF | 724 | 0 | 7.100 | 0 | Cardinal Cogen, Palo Alto | 3/13/96 |

| Current Owner | Certificate Number | Pollutant Quantity (tpy) | | | Origin, Location | Date Banked |
|---|---|---|---|---|---|---|
| | | POC | NOx | $SO_2$ | | |
| Calpine | 896 | 0 | 305.594 | 90.000 | PG&E Potrero Power Plant, San Francisco | 4/26/84 |
| Total Offsets Available | | 26.522 | 311.694 | 90.000 | | |
| Offset Obligation | | 7.500 | 27.945 | 13.730 | | |
| Difference | | +19.022 | +283.749 | +76.270 | | |
| Balance | | 19.022 | 283.749 | 76.270 | | |

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 was published in the San Jose Mercury News on March 23, 2005 inviting written public comment on the revised PDOC that was issued on March 14, 2005.  Written comments were submitted to the District by the CEC, USEPA, and Michael Boyd, a private citizen.  The comments were carefully considered and written responses have been sent to each commentor with a copy of the FDOC.  Where appropriate, the FDOC includes changes in response to those comments.

**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 2-3-405, this Final Determination of Compliance (FDOC) serves as the APCO's final decision that the proposed modified power plant will meet the requirements of all applicable BAAQMD, state and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-403, the FDOC has satisfied the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the FDOC is not considered a final determination of whether the facility can be constructed or operated. Pursuant to Regulation 2-3-405, 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 | | 288 lb/day | |
| d. $PM_{10}$ | 96 lb/day | | 96 lb/day | |
| e. $SO_2$ | 18.9 lb/day | | 18.9 lb/day | |

(basis: cumulative increase)

11. Within sixty (60) 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: BAAQMD Toxics Risk Management Policy)

    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 startup is kept to a minimum, consistent with good engineering practice. 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. For purposes of this Part, a start-up period of 240 minutes or less shall be considered kept to a minimum consistent with good engineering practice. Should it be determined that good engineering practice requires a different time period for a start-up, the owner/operator may operate the gas turbines such that startups do not exceed that time period, as approved in writing by the APCO. (Basis: BACT)

21. Turbine Shutdown: The owner/operator shall operate the gas turbines so that the duration of a shutdown is kept to a minimum, consistent with good engineering practice. Shutdown begins with the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. For purposes of this Part, a shutdown period of 30 minutes or less shall be considered kept to a minimum consistent with good engineering practice. Should it be determined that good engineering practice requires a different time period for a shutdown, the owner/operator may operate the gas turbines such that shutdowns do not exceed that time period, as approved in writing by the APCO. (Basis: BACT)

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 | 417.2 | 1,668.8 | 98.5 |
| 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: | 12,000 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 29a 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 29b 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. Recordkeeping: 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 7.5 tons of valid POC emission reduction credits and 27.945 tons of valid NOx 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. <u>Title IV and Title V Permits</u>: 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 44) 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 Final 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, the revised Preliminary Determination of Compliance (PDOC) has satisfied the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. A notice inviting written public comment on the proposed modifications to the LECEF was published in the San Jose Mercury News on March 23, 2005. Written comments on the revised PDOC were submitted by the CEC, USEPA, and Michael Boyd, a private citizen. All comments received during the 30-day public comment period will be considered and responses to those comments will be prepared. Where appropriate, this Final Determination of Compliance (FDOC) includes changes in response to those comments.

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

# APPENDIX D

## Engineering Evaluation for 2010 Phase II ATC Renewal

# Request for Renewal

# Authority to Construct
# for the
# Los Esteros Critical Energy Facility
# Combined-Cycle Conversion (Phase 2)

# Plant Number 13289

## In Conjunction With

## California Energy Commission
## License Amendment
## Proceeding 03-AFC-2C

Bay Area Air Quality Management District
Authority to Construct Number 8859

November 2, 2010

Weyman Lee, P.E.
Senior Air Quality Engineer

**APPLICTION FOR AUTHORITY TO CONSTRUCT RENEWAL**

**LOS ESTEROS CRITICAL ENERGY FACILITY**

**Application Number 8859**

**Plant Number 13289**

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## Appendices



## Tables

# I. Introduction and Summary

Los Esteros Critical Energy Facility, LLC has requested a renewal of the Authority to Construct (ATC) for Phase II of the Los Esteros Critical Energy Facility (LECEF2). The LECEF Phase II project is a conversion of the facility from a simple-cycle facility to a more efficient combined-cycle operation. The California Energy Commission (CEC) licensed the Phase II project on October 11, 2006, and the District subsequently issued the Authority to Construct for the Phase II conversion project on August 22, 2007,[5] with a two-year term. The two-tear term has expired, and so the applicant is now seeking to have the Authority to Construct renewed for another two years.

This application is being processed under the auspices of the CEC power plant licensing process, which supersedes District permitting authority under the Warren-Alquist State Energy Resources Conservation and Development Act (Warren-Alquist Act).[6] The applicant filed a petition for amendment of its CEC license on October 30, 2009, which included a request to revise certain Conditions of Certification so they meet the requirements for renewal of the Authority to Construct. The CEC will be making its determination on the applicant's petition under its Warren-Alquist licensing authority, and it has requested the District's input on current air quality requirements. This analysis has been prepared in response to that request. Upon determination by the CEC that the project meets current air quality requirements and amendment of any license conditions that need to be brought up to date, the District will then be able to renew the Authority to Construct consistent with the CEC's license.

Renewal of the Authority to Construct is subject to District Regulation 2-1-407.1, which provides that an Authority to Construct may be renewed for an additional two years upon a showing that the project will meet current Best Available Control Technology (BACT) and offset requirements as defined in District Regulations 2-2-301, 302, and 303. This document provides the District's evaluation of the project's compliance with the current BACT and offset requirements in accordance with Regulation 2-1-407.1 as a prerequisite for renewal of the Authority to Construct. The District will submit this analysis to the CEC for use in its license amendment process to help the CEC with its determination as to whether the facility meets current BACT and offset requirements.

The District's review of current BACT and offsets as described herein has found that the majority of the BACT and offset conditions established for the CEC license and Authority to Construct meet current standards, with several exceptions that will need to be modified. Specifically, the District has found that under current BACT standards the limit on carbon monoxide emissions of 9.0 ppm (3-hour average) should be lowered to 2.0 ppm (1-hour average), and the limit on precursor organic compounds (POC) of 2.0 ppm (3-hour average) should be lowered to 1.0 ppm (1-hour average). In addition, the District found that the existing

[5] BAAQMD Application No. 8859.
[6] *See* Public Resources Code section 25500 ("The issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency, or federal agency to the extent permitted by federal law, for such use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency, or federal agency to the extent permitted by federal law.)"

limits on the duration of turbine startups should be reduced to meet current BACT standards, and should also have numerical emissions limits added for startup and shutdown events. The District has also found that the limit on total dissolved solids (TDS) content in the cooling water can feasibly be lowered to 6,000 ppm. At this level, particulate emissions from the cooling system will be reduced to a level where the BACT requirement is not triggered, meaning that the cooling system will be consistent with current BACT requirements. The District's BACT review is set forth in detail in Section III.

As noted above, under the Warren-Alquist Act any renewal of the Authority to Construct must be consistent with the license issued for the Phase II conversion project by the CEC. As a result, the District cannot issue a renewed ATC with conditions that are inconsistent with the conditions of the CEC's license. Upon incorporation of current BACT and offset conditions into the CEC license for the facility, the District can renew the ATC with these revised conditions.

ATC renewals are not subject to the public notice and comment provisions applicable to initial permit issuance under District Regulations 2-2-405 through 2-2-407. The CEC will provide an opportunity for the public to comment on the conditions of the renewed ATC during the CEC's license amendment process, however. If the CEC amends its license for the LECEF, the District will issue the renewed ATC consistent with the CEC license.

## II. Project Description

The existing LECEF facility is a simple-cycle "peaker" power plant that uses four natural gas fired LM6000PC combustion turbines to generate a nominal 190 megawatts (MW) of electricity. The current facility was licensed by the CEC in July of 2002, and it became fully functional in March of 2003.[7] The current simple-cycle facility was licensed as Phase I of a two-phase project, with Phase II to consist of a conversion to a more efficient combined-cycle operation. In a combined-cycle operation, the waste heat in the turbine exhaust is recovered to make steam to turn a steam turbine and generate additional electric power, which increases the plant's overall efficiency.

The LECEF Phase II conversion project will add four heat recovery steam generators (HRSGs) to make steam from the turbine exhaust, a steam turbine generator to generate electricity from the steam, and a six-cell cooling tower. Each HRSG will be equipped with a duct burner to provide a maximum 139 MMBtu/hr of supplemental heat. This is a "4x1" configuration in which the steam output from the four heat recovery steam generators will be used to feed one steam turbine generator. The modified LECEF2 facility will have a nominal output of 320 MW as a result of the addition of the nominal 130 MW steam turbine generator. In addition, the maximum rated heat input of each gas turbine will increase from 472.6 MMBtu/hr (HHV) to 500 MMBtu/hr (HHV).

Exhaust concentrations of NOx, CO, and POC will be reduced substantially when the LECEF is converted to a combined-cycle power plant.[8] To achieve these reductions, the existing high-

[7] *See* Commission Decision, Los Esteros Critical Energy Facility II, Phase 2, Application for Certification (03-AFC-2), October 2006 ("LECEF Phase 2 Certification"), at 1.
[8] *See* Tables 1, 2, and 3 for existing simple-cycle and proposed combined-cycle emission limits.

temperature selective catalytic reduction (SCR) and oxidation catalysts will be replaced with new low-temperature SCR systems and new oxidation catalysts.[9]

The CEC issued its license for the Phase II combined-cycle conversion project in October of 2006,[10] and the District issued its Authority to Construct for the Phase II project in August of 2007. The applicant submitted its application for renewal of the ATC on June 5, 2009, which was prior to the expiration of the initial ATC for the Phase II project as required by Regulation 2-1-407.

The emission limits for the existing Phase I simple-cycle plant are presented in Table 1 below.[11]

**Table 1: Existing Emission Limits for the LECEF Phase I Simple-Cycle Plant**

| Pollutant | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Emission Limit | 5.0 ppmvd 3-hr avg. | 2.0 ppmvd 3-hr avg. | 2.5 lb/hr | 4.0 ppmvd 3-hr avg. | 0.33 lb/hr[a] |

[a] calculated based on an annual average sulfur content of 0.25 gr/100 dscf in natural gas fuel

The emission limits for the Phase II combined-cycle plant as approved in 2007 are presented in Table 2 below.[12]

**Table 2: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC in 2007**

| Pollutant | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Emission Limit | 2.0 ppmvd[a] 1-hr avg. | 2.0 ppmvd 3-hr avg. | 2.5 lb/hr | 9.0 ppmvd 3-hr avg. | 1.8 lb/hr[b] |

[a] With short-term excursion language for transient load conditions that allows up to 5 ppm $NO_x$ concentration.
[b] calculated based on maximum sulfur content of 1.0 gr/100 dscf in natural gas fuel

[9] High-temperature SCR units are required for the simple-cycle turbine due to high exhaust temperatures. The combined-cycle plant will recover heat from the turbine exhaust, lowering its temperature, enabling low-temperature SCR systems to be used.
[10] *See* LECEF Phase 2 Certification at 34.
[11] The detailed calculations are found in Final Determination of Compliance, Application No. 3213.
[12] The detailed calculations are found in the Final Determination of Compliance for the Los Esteros Critical Energy Facility, Application No. 8859, June 28, 2005.

The revised emission limits for the Phase II ATC renewal based on current BACT as discussed in this evaluation are presented in Table 3 below:

**Table 3: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC Renewal in 2010**

| Pollutant | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Emission Limit | 2.0 ppmvd[a] -hr avg. | 1.0 ppmvd 1-hr avg. | technology[b] | 2.0 ppmvd1-hr avg. | technology[b] |

[a] With no provision for transient load excursions
[b] The District has established BACT for $PM_{10}$ and $SO_2$ as a control technology and not as a numerical emissions limit. This determination is discussed in Sections III.A.3. and III.A.4. below. There will be no difference in the amount of $PM_{10}$ and $SO_2$ that will be emitted.

A comparison of annual emissions limits for the facility in the Phase I ATC, the initial Phase II ATC, and the Phase II ATC renewal is presented in Table 4 below:

**Table 4: Comparison of Maximum Annual Facility Emission Limits (tons/yr)**

| | $NO_x$ | POC | $PM_{10}$ | CO | $SO_2$ |
|---|---|---|---|---|---|
| Permit Limits for the Phase I Simple-Cycle Plant as approved in 2002 | 74.9 | 21.0 | 43.8 | 72.9 | 5.8 |
| Permit Limits for the Phase II ATC issued in 2007 | 99.2 | 28.3 | 53.3 | 98.6 | 8.4 |
| Permit Limits for the Phase II ATC Renewal Based on Current BACT | 95.21 | 12.31 | 44.24 | 53.44 | 6.45 |

In addition, Calpine has requested that its ammonia slip limit be reduced from 10 ppm to 5 ppm as part of the ATC renewal for this project. The conversion to a combined cycle facility will allow the use of a low-temperature SCR system that will have a higher NOx abatement efficiency than the high-temperature SCR system that it will replace. The higher efficiency of the low-temperature SCR allows the plant to reduce the injection of excess ammonia to ensure proper NOx and ammonia mixing and distribution across the catalyst.

**<u>Permitted Source Descriptions</u>:**

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

**S-1 Combustion Gas Turbine #1 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-9 Oxidation Catalyst and A-10 Selective Catalytic Reduction System**

**S-2 Combustion Gas Turbine #2 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-11 Oxidation Catalyst and A-12 Selective Catalytic Reduction System**

**S-3 Combustion Gas Turbine #3 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-13 Oxidation Catalyst and A-14 Selective Catalytic Reduction System**

**S-4 Combustion Gas Turbine #4 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-15 Oxidation Catalyst and A-16 Selective Catalytic Reduction System**

**S-5 Fire Pump Diesel Engine, Clarke 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 (HHV) abated by A-9 Oxidation Catalyst, and A-10 Selective Catalytic Reduction System**

**S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-11 Oxidation Catalyst, and A-12 Selective Catalytic Reduction System**

**S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-13 Oxidation Catalyst, and A-14 Selective Catalytic Reduction System**

**S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-15 Oxidation Catalyst, and A-16 Selective Catalytic Reduction System**

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

The facility also has an existing one-cell cooling tower that is exempt from District permitting requirements.

# III. Best Available Control Technology (BACT) Review

The first requirement for renewal of an Authority to Construct under District Regulation 2-1-407.1.2 is that the facility must meet current Best Available Control Technology (BACT) requirements under District Regulation 2-2-301. District Regulation 2-2-301 requires that the LECEF Phase II project use the Best Available Control Technology to control $NO_x$, CO, POC, $PM_{10}$, and $SO_x$ emissions because it will have the potential to emit over 10 pounds per day of each of those pollutants. 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 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 it must be commercially available, 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/TBACT Workbook.

The District has reviewed the Phase II conversion project under Regulation 2-1-407.1.2 to determine whether it meets current BACT standards. The results of the District’s BACT review are described in the following subsections.

## III.A. BACT for Gas Turbine and HRSG Duct Burners

The following section provides the District’s BACT review by pollutant for the gas turbines and HRSG duct burners. Because each gas turbine and its associated HRSG/duct burners will exhaust through a common stack and be subject to common emission limitations, the BACT review is made for each Gas Turbine/HRSG power train as a combined unit.

### III.A.1. Nitrogen Oxides (NOx)

The simple-cycle LECEF operation 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 startups and shutdowns. The Phase II Authority to Construct (ATC) provides that when the facility is converted to combined-cycle operation, the NOx limit will be reduced to 2.0 ppmv @ 15% $O_2$, dry averaged over one hour with limited allowable excursions (not to exceed 5 ppmv) due to transient conditions such as rapid load changes. The District has reviewed this BACT determination and found that the 2.0 ppm limit meets current BACT, but has concluded that the excursion language can no longer be justified as BACT. The District has therefore determined that current BACT for NOx is an emission limit of 2.0 ppm averaged over one hour at all times (excluding startups and shutdowns).

The District reviewed its BACT guideline for large combined-cycle gas turbines, Guideline 89.1.6., and found that it has not been revised since the initial Phase II ATC was issued. The District also reviewed permit limits from permits that have been issued for similar facilities recently, and did not find any permit limits more stringent than the 2.0 ppm (1-hour average) in any Authority to Construct.[13] The District also reviewed the available technologies for controlling NOx from combined-cycle gas turbines, and has not found any additional technologies that could be used here to achieve a BACT limit below 2.0 ppm. The facility will use water injection in the combustion turbines to help minimize the formation of NOx during combustion, and a Selective Catalytic Reduction (SCR) system to control NOx in the exhaust stream. The District has not found any more effective control devices or techniques that could appropriately be required as BACT for this project.

- ***Consideration of NOx Control Technologies:***

The District considered two additional technologies for controlling NOx emissions in its BACT review. The first is a recent development in dry low-NOx combustor technology that can achieve 15 ppm NOx emissions in the turbine exhaust (before abatement by any add-on control device). This 15 ppm emissions rate would be an improvement compared to the LM6000 PC turbines that Calpine is currently using at the facility, which use water injection for NOx control are rated at 25 ppm NOx emissions in the turbine exhaust. Calpine used the LM6000 PC turbines because they equaled the best NOx emissions performance that could be achieved at the time,[14] and because turbines using water injection are capable of producing a higher power output.[15] Because water injection was equivalent to dry low-NOx combustor technology at the time in terms of NOx reduction efficiency, either of them would have been consistent with the BACT requirement.

[13] One facility that the District reviewed, the IDC Bellingham facility in Massachusetts, has a two-tiered NOx emissions limit that requires the facility to maintain emissions below 1.5 ppm during normal operations but allows emissions of up to 2.0 ppm as absolute not-to-exceed limit. This two-tiered limit recognizes that emissions can be highly variable depending on operating circumstances, and will have relatively lower emissions at some times and relatively higher emissions at other times. The proposed LECEF2 is expected to exhibit the same type of variation in emissions under the various operating scenarios it will face, and will have emissions as high as 2.0 under some circumstances. The IDC Bellingham permit therefore supports the District's conclusion that 2.0 ppm is current BACT for NOx.

[14] *See* GE Energy Estimated Engine Performance for LM6000 PD-Sprint and LM6000 PC-Sprint reports dated April 30, 2004.

[15] *Id.*

New dry low-NOx combustor technology has recently become available, however, and so the District evaluated whether Calpine should be required to retrofit the facility with this technology as part of the LECEF Phase II project. But retrofitting an existing facility with completely new turbines is not normally required for this type of project and so it cannot be "achieved in practice" for purposes of the BACT requirement. Similarly, the high costs involved would render it not sufficiently cost-effective to require as BACT. The cost of the conversion would range between $11.25 and $11.75 million per turbine.[16] There would most likely be some additional NOx benefit to be gained from this additional cost, although it is not clear that any additional benefit would be significant and there is no guarantee that new turbines would allow the facility to consistently achieve NOx emissions below 2.0 ppm. The District conservatively assumed for purposes of its analysis that dry low-NOx combustors could allow the facility to achieve a reduced NOx emissions rate of 1.5 ppm. At this reduced rate, an additional 16.1 tons of NOx per year could be avoided. The cost to achieve a reduction in annual emissions of 16.1 tons of NOx would be an annualized cost of $8.5 million for an incremental cost-effectiveness of about $530,000 per ton.[17] Achieving emissions reductions at this cost would therefore not be sufficiently cost-effective to require as BACT.[18] Note that this analysis does not consider the ancillary costs and environmental consequences related to junking the existing LECEF's equipment in favor of the new equipment.

The second technology the District considered is an add-on control technology known as EMx™. EMx™ (formerly SCONOx™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of $NO_x$, as well as CO, VOC and optionally $SO_x$ emissions. EMx could potentially be an improvement over SCR as an add-on control device for achieving NOx reductions because it does not use ammonia. Ammonia has the potential, under certain atmospheric conditions, to react with nitric acid in the atmosphere to form ammonium nitrate, which can be a form of fine particulate matter ($PM_{2.5}$). The atmospheric chemistry regarding the extent to which this process actually happens under real-world conditions has historically not been well understood, and the District's scientific understanding has been until recently that there was insufficient nitric acid in the atmosphere to make secondary $PM_{2.5}$ formation a significant concern. As a result, the District has not historically regulated ammonia as a $PM_{2.5}$ precursor, and has not found that EMx's lack of ammonia slip emissions would provide any significant benefit over SCR.

The District has recently been reevaluating whether ammonia is in fact a significant contributor to secondary $PM_{2.5}$. The focus of the District's further evaluation has been a computer modeling exercise designed to predict what $PM_{2.5}$ levels will be around the Bay Area, given certain assumptions about emissions of $PM_{2.5}$ and its precursors, about regional atmospheric chemistry,

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[16] *See* email from Michael T. McCarrick (GE Power & Water, Repowering) to Larry Salguero (Calpine Corp., Engineer III, Transaction Support) Subject: LM6PC to PF Conversion, October 1, 2010 (quoting an original equipment manufacturer (OEM) Cost of $9.5 to 10 MM; Field Service and Technical Support costs of $750,000 and Labor and Materials costs of $1,000,000, for a total of $11.25 MM to 11.75 MM per turbine).
[17] *See* Spreadsheet, NOx incremental 2 to 1.5 PF Turbines, prepared by Barbara McBride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.
[18] The District's guideline for cost-effectiveness for NOx emission reductions is $17,500 per ton. See BAAQMD BACT Policy and Implementation at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm. The cost-effectiveness of requiring LM 6000 PF turbines here would be well over this threshold.

and about prevailing meteorological conditions.[19] The results of this study, while still preliminary, confirm that the predominant limiting factor in the formation of secondary particulate matter is the availability of nitric acid, not ammonia. However, the study suggests that the amount of available nitric acid is not uniform and varies in different locations around the Bay Area, and that in some locations there is available nitric acid to react with ammonia. The District's model thus predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes in ambient $PM_{2.5}$ levels of between 0% and 4%, depending on the availability of nitric acid. While this analysis is still preliminary, it suggests that that ammonia restrictions might play a role in a regional strategy to reduce $PM_{2.5}$.[20] The District is therefore evaluating whether it should impose regulations on ammonia emissions as a $PM_{2.5}$ precursor, and is also taking a harder look at whether it should require EMx as a BACT control technology for NOx reductions instead of SCR.

The District therefore evaluated whether EMx would be an improvement over SCR, which has been proven to be able to keep NOx emissions below 2.0 ppm for a facility like this one. EMx has only been used at one facility with a gas turbine of a similar size to this facility, at Redding Power Plant Unit No. 5, a 45-MW combined-cycle facility in Shasta County, CA. The Shasta County Air Quality Management District evaluated EMx™ at that facility under a demonstration $NO_x$ limit of 2.0 ppm. After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EMx™, and concluded that "Redding Power is not able to reliably and continuously operate while maintaining the $NO_x$ demonstration limit of 2.0 ppmvd @ 15% $O_2$."[21] Although the manufacturer maintains that such problems have been overcome, concerns remain about how consistently the technology would be able to perform. Recent communications with the Shasta County Air District confirm that the earlier conclusions about the achievability of a lower limit remain valid.[22] In addition, monthly reports of Continuous Emissions Monitoring System (CEMS) data submitted by Redding Power Plant to Shasta County Air District during the past three calendar years indicate that emissions have often been substantially higher.[23] Because EMx cannot achieve the high level of emissions performance that SCR is capable of, the District is requiring SCR to be used instead of EMx as the BACT add-on control technology for NOx.

- ***Consideration of NOx Emissions Limit Below 2.0 ppm:***

The District also considered whether it would be feasible to implement a $NO_x$ permit limit below 2.0 ppm. Consistent compliance with a limit below 2.0 ppm has never been demonstrated in practice, and the equipment vendors that the District contacted regarding this issue stated that

[19] *See* BAAQMD, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Oct. 1, 2009), at p. 8 ($PM_{2.5}$ Modeling Report). (available at: www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Research%20and%20Modeling/PM-data-analysis- and-modeling-report.ashx )
[20] *Id* at pp. E-3 – E-4.
[21] Letter from R. Bell, Air Quality District Manager, Shasta County Air Quality Management District, to R. Bennett, Safety & Environmental Coordinator, Redding Electric Utility, June 23, 2005.
[22] Telephone conversation between W. Lee and R. Bell, October 25, 2010. Mr. Bell confirmed that unit No. 5 demonstrated that it is not capable of meeting a NOx limit of 2 ppm (1-hr average) consistently. Unit #5 is currently required to meet a NOx limit of 2.5 ppm (rolling 1-hr average).
[23] *See* Summary of REU-Unit 5 Operating and NOx Data.

they would not be able to guarantee that a lower limit could be achieved.[24] The District nevertheless considered whether it would be technologically feasible to do so. The District has concluded that imposing a NOx emissions limit below 2.0 ppm cannot be justified as BACT at this time.

Additional NOx reductions could potentially be achieved by increasing the amount of catalyst or size of the catalyst bed in the SCR system. It would be difficult to achieve any substantial additional reductions, however, because at the very low NOx levels that are currently being achieved by SCR additional efforts produce diminishing returns. SCR performance for $NO_x$ control is highly dependent on the $NO_x$-to-ammonia reaction stoichiometry. At stoichiometric conditions, there would be just enough ammonia to react with the $NO_x$ with no additional ammonia slip exhausted out the stack. It becomes highly challenging to ensure a uniform distribution of ammonia to $NO_x$ over the entire gas turbine operating range when NOx concentrations are very low. Alternatively, some vendors have considered staging two separate ammonia injection grids and catalyst beds in series in order to achieve an optimal distribution of ammonia to $NO_x$ that might maintain emissions at less than 2.0 ppm $NO_x$ over the entire gas turbine operating range. But this approach has its own drawbacks, such as increasing the backpressure on the turbine exhaust and decreasing the efficiency of the turbine resulting in higher emissions per megawatt of power generated. Moreover, no installation using a staged series of ammonia injection grids has been demonstrated in practice. Additionally, temperature variations across the catalyst bed also impact SCR performance. At progressively lower NOx concentrations, these variations have an increasingly significant impact on maintaining stoichiometric conditions. For all of these reasons, it becomes increasingly difficult to gain additional NOx reductions as concentrations are driven to extremely low levels simply by increasing the amount of catalyst or the size of the catalyst bed. Increasing the amount of catalyst or size of catalyst bed theoretically can provide for more NOx reduction, but for a number of reasons simply adding more catalyst reaches a point of diminishing returns as NOx levels approach zero.[25]

In addition, achieving lower NOx emissions levels would have other potential offsetting impacts. Ensuring emissions consistently remain below 2.0 ppm could potentially cause a significant increase in ammonia slip and require a higher ammonia slip permit limit. Implementing a $NO_x$ limit below 2.0 ppm would also likely require an increase in the frequency of catalyst change-outs to maintain compliance. This would have both cost impacts and ancillary environmental impacts, because the old catalyst must be disposed of as hazardous waste, because the larger amount of catalyst needed would generate more spent catalyst to be disposed of, and because additional energy and natural resources would need to be used to produce the new catalyst. A $NO_x$ permit limit below 2.0 ppm limit would also result in additional maintenance, which adds to operating costs and requires maintenance outages during which the plant is unavailable to meet demand. For example, achieving very low NOx limits would require the seals in the SCR system to be maintained to very tight tolerances to minimize the amount of NOx that may slip by them.

[24] *See, e.g., See* email from Shaun P. Hennessey (Manager of Thermal Design, Nooter/Eriksen, Inc.) to Paul C. Berthiaume P.E. (Chief Mechanical Engineer, Calpine), Subject: Los Esteros NOx Conversion, May 20, 2010; email from Vijay Patel (Deltak) to Paul C. Berthiaume, P.E. (Chief Mechanical Engineer, Calpine Corp.), October 6, 2010.

[25] *See generally* M. Schorr & J. Chalfin, *Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?*, GE Power Generation, Publication No. GER 4172, September, 1999.

With a $NO_x$ permit limit below 2.0 ppm, it is likely that more frequent outages will be required to inspect and maintain these seals, which adds to the cost and could significantly impact the plant's availability to support the grid.

Finally, assuming that an SCR system could be designed to achieve emissions below 2.0 by increasing the amount of catalyst or the size of the catalyst bed, the system would have to be able to operate to maintain compliance at all times, including during periods of transient load. Compliance is much more difficult during such periods because the SCR system's ammonia injection control system is limited in how quickly it can respond to rapidly changing conditions. The amount of ammonia being injected is determined based on turbine operating conditions and the $NO_x$ concentration at the stack exhaust. There is an optimal amount of ammonia based on the incoming $NO_x$ and the ammonia injection system provides a slight excess to ensure the $NO_x$ emissions are minimized while ammonia slip levels are also minimized. When gas turbine load is ramped quickly, its NOx emissions can change much more rapidly than the ammonia injection system can respond due to the lag time in the ammonia injection control system and the $NO_x$ continuous emission monitor. This control system lag and continuous emission monitor (CEM) lag time make meeting a permit limit below 2.0 ppm $NO_x$ averaged over one hour much more difficult during rapid load changes.

Designing an SCR system to consistently maintain compliance with a limit below 2.0 ppm would also be more difficult because transient load conditions and fast ramp rates are expected to become more common in the coming years as California moves to more renewable power generation. Renewable sources of electrical power such as wind and solar are much more intermittent and uncertain that traditional power plants. Fossil fuel fired plants will be needed to fill in the gaps when the sun is not shining or the wind is not blowing, and they will be required to ramp up quickly when needed and then ramp back down when renewable sources come back on-line.[26] For this reason, facilities such as the LECEF Phase II project are expected to experience a significantly increased amount of transient load conditions, although it is difficult to predict with certainty exactly how these facilities will need to operate. An SCR system would need to be designed to operate at a very high degree of efficiency in order to ensure that it would be able to maintain compliance with a short-term NOx limit below 2.0 during all potential transient load conditions. Moreover, given the uncertainty as to how exactly the facility will need to operate in support of additional renewable generation, it would be difficult to predict the maximum design parameters that would be needed to ensure compliance.

Based on all of this analysis, the District has concluded that there is insufficient evidence on which to make a determination that a lower NOx emissions limit can be justified as BACT for this facility. Although it may be possible in theory to design an enhanced SCR system that could potentially be more effective in reducing NOx, there is substantial uncertainty as to how effective such an enhanced system would actually be in consistently achieving a lower permit limit. Moreover, even if a lower limit could theoretically be achieved, there is substantial uncertainty over how the SCR system would need to be designed to do so given the changes in power plant operating scenarios that are expected as California moves to more renewable power sources, and in particular the greater incidence of transient load conditions. The District is also concerned that if the facility is subjected to a lower limit and finds that it cannot achieve it during

[26] Integration of Renewable Resources, Operational Requirements and Generation Fleet Capability at 20% RPS, August 31, 2010, California ISO, pg. iii.

transient loads, the facility would not be able to be operated to support renewable resources as readily which would hinder California's efforts to develop those resources. And finally, the District is also mindful of the additional costs and ancillary adverse environmental impacts that would be associated with an enhanced SCR system. Although additional costs and ancillary impacts can be acceptable where justified by the increased effectiveness of a better add-on control system under a BACT analysis, there is little clear indication that additional NOx reductions beyond the very stringent 2.0 ppm levels that are currently being achieved would be worth it here (to the extent that any additional reductions could even be obtained in practice). Given the high degree of uncertainty regarding what level of additional NOx reductions could actually be achieved, what would be required from a technical standpoint to achieve any such additional reductions, and what the adverse ancillary impacts would be, the technical information available at this point does not provide a sufficiently certain basis to support a BACT determination that a NOx emissions limit below 2.0 should be required. The District has considered all of this evidence and has concluded that the evidence does not support imposing a NOx emissions limit below 2.0 ppm as BACT for the LECEF Phase II project.

- ***Consideration of Excursion Language:***

The District also considered whether the excursion language in the Phase II ATC meets current BACT requirements. (See Condition 19.g, allowing up to 320 hours per year for short-term excursions above the 2.0 ppm NOx limit up to 5.0 ppm NOx.) The District found that a number of similar facilities have NOx permit limits at 2.0 ppm (1-hour) with no excursion language, suggesting that 2.0 ppm without excursion language is the achieved-in-practice level of emissions control. In addition, the applicant has not voiced any objection to removing the excursion language from the permit. The District has therefore concluded that the excursion language is not consistent with current BACT and should be removed from the renewed ATC.

- ***Conclusions:***

Based on the foregoing review, the District has concluded that the NOx BACT limit of 2.0 ppm, averaged over one hour, will meet current BACT (with the excursion language removed).

### III.A.2. Carbon Monoxide (CO)

The Phase II Authority to Construct established a CO limit of 9.0 ppm averaged over three hours. The District established the CO limit at this level based on concerns that using water injection to reduce NOx formation during combustion would cause increased CO formation because of lower flame temperatures. Lower flame temperature decreases combustion efficiency, which results in CO formation due to incomplete combustion. When LECEF 2 was originally permitted, the operator provided test data demonstrating the effect of the increase in the water injection rate that would be required to allow the turbines to comply with the 2.0 ppm $NO_x$ limit. As the $NO_x$ emission concentration after abatement by the SCR system 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 was expected that the CO emissions would increase further as the NOx emissions are controlled to meet a 2.0 ppmv limit on $NO_x$. Based on the demonstrated increases in CO emissions that occurred as the water injection rates were increased to reduce $NO_x$ emissions, the applicant requested that the maximum allowable (not-to-be-exceeded) CO limit be increased to

9.0 ppmv. The District agreed that the proposed CO limit of 9.0 ppm was reasonable when combined with the 2.0 ppm NOx limit. Thus, the ATC was issued with a CO limit of 9.0 ppmvd averaged over three hours.

The District has reviewed this BACT determination and has concluded that current BACT requires a lower limit. The District reviewed a number of other combined-cycle power plants to evaluate what CO emissions limits have been achieved in practice, based on a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse. The search results from these databases are summarized in Table 5 below.[27] The table identifies both $NO_x$ limits and CO limits because they are dependent on each other. With a lower $NO_x$ limit, greater leeway must be given in the CO limit because reducing $NO_x$ normally results in increasing CO. The projects are presented in order of descending CO concentrations and averaging times.

**Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers**

| Facility | $NO_x$ ppmvd @ 15% $O_2$ | CO ppmvd @ 15% $O_2$ | Operational Status |
|---|---|---|---|
| Hanging Rock, OH-0252 | 3 (3-hr) | 9 (24-hr) | Unknown |
| FPL Turkey Point, FL-0263 | 2 (24-hr) | 8 (24-hr) | Unknown |
| La Paloma, SJVAPCD | 2.5 (1-hr) | 6 (3-hr) | In Operation |
| Mountainview San Bernadino County | 2.5 (1-hr) 2.0 (1-hr) in 2005 | 6 (3-hr) | In Operation |
| Three Mountain, Shasta County | 2.5 (1-hr) | 4 (3-hr) | Not Built |
| SMUD Clay Station, SMAQMD | 2 (1-hr) | 4 (3-hr) | Unknown |
| Elk Hills, SJVAPCD | 2.5 (1-hr) | 4 (3-hr) | In Operation |
| Sunset Power, SJVAPCD | 2 (1-hr) | 4 (3-hr) | Unknown |
| Palomar Energy Project | 2 (1-hr) | 4 (3-hr) | In Operation |
| Sacramento Municipal Utilities District, Consumnes | 2 (1-hr) | 4 (3-hr) | In Operation |
| San Joaquin Valley Energy Center | 2 (1-hr) | 4 (3-hr) | Not Built |
| Calpine Facility Sutter, Feather River AQMD | 2.5 (1-hr) | 4 (24-hr) | In Operation |
| Sierra Pacific Power Company, Tracy Station, NV-0035 | 2 (3-hr) | 3.5 (3-hr) | Unknown |

[27] In addition to reviewing recent permit limits, the District also reconsidered its BACT technology choice analysis. The facility will use an oxidation catalyst and good combustion practices as the BACT technologies to control CO emissions, as discussed in the District's evaluation for the initial Phase II ATC. The only additional control technology available for use in controlling CO emissions is EMx, which the District evaluated above and concluded is not as effective as SCR and is therefore not BACT. The District has therefore concluded that the current technology choice for CO continues to satisfy the BACT requirement.

**Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers**

| Facility | $NO_x$ ppmvd @ 15% $O_2$ | CO ppmvd @ 15% $O_2$ | Operational Status |
|---|---|---|---|
| ANP Blackstone, MA-0024 | 2 (1-hr) No Steam<br>3.5 (1-hr) Steam Inj. | 3.0 (1-hr) | In Operation |
| Welton Mohawk, AZ-0047 | 2 (3-hr) | 3 (3-hr) | Unknown |
| Colusa Generating Station | 2 (1-hr) | 3 (3-hr) | Not Built |
| Rocky Mountain Energy Center, CO-0056 | 3.0 (1-hr) | 3 | In Operation |
| Turner Energy Center, OR-0046 | 2.0 (1-hr) | 2.0 (3-hr)>70% load,<br>3.0 (3-hr)<70% load | Not Built |
| Berrian Energy Center, MI-0366 | 2.5 (24-hr) | 2.0 (3-hr) | Unknown |
| BP Cherry Point, WA-0328 | 2.5 (3-hr) | 2 (3-hr) | Unknown |
| Wanapa Energy Center, OR-0041 | 2 (3-hr) | 2 (3-hr) | Not Built |
| Morro Bay – Duke | 2 (1-hr) | 2 (3-hr) | Not Built |
| Carlsbad Energy Center, SDAPCD | 2 (1-hr) | 2 (1-hr)<br>2 (3-hr)<br>Transient | Not Built |
| Goldendale Energy, WA-0302 | 2 (3-hr) | 2 (1-hr) | In Operation |
| Sumas Energy 2, WA-0315 | 2 (3-hr) | 2 (1-hr) | Not Built |
| IDC Bellingham, MA | 1.5/2.0 (1-hr) | 2 (1-hr) | Not Built |
| Magnolia, SCAQMD | 2 (3-hr) | 2 (1-hr) | In Operation |
| Sithe Mystic, MA-0029 | 2 (1-hr) | 2 (1-hr) | In Operation |
| Sithe Fore River, MA | 2 (1-hr) | 2 (1-hr) | In Operation |
| Russell City Energy Center | 2 (1-hr) | 2 (1-hr) | Not Built |
| Southern Company McDonough Combined Cycle, GA-0127 | 6 (May thru Sept)<br>15 (30 day Rolling Avg) | 1.8 (3-hr) | In Operation |
| Kleen Energy Systems, CT-0151 | 2 (1-hr) | 0.9 (1-hr) No Duct Burner<br>1.7 (1-hr) Duct Burner | Not Built |

**Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers**

| Facility | $NO_x$ ppmvd @ $15\%O_2$ | CO ppmvd @ $15\%O_2$ | Operational Status |
|---|---|---|---|
| CPV Warren, VA-0308, Scenario 1, GE Frame 7FA | 2 (1-hr) | 1.3 (3-hr) No Power Aug. 1.8 (3-hr) Power Aug. No Duct Burner<br>2.5 (3-hr) Power Aug., Duct Burner | Not Built |
| CPV Warren, VA-0308, Scenario 2, GE Frame 7FA | 2 (1-hr) | 1.2 (3-hr) without Duct Burner 1.3 (3-hr) Duct Burner | Not Built |
| CPV Warren, VA-0308, Scenario 3, Siemens F-Class | 2 (1-hr) | 1.8 (3-hr) No Duct Burner 2.5 (3-hr) with Duct Burner | Not Built |

Notes:

a. Information presented is from a database search of a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse for recent permits issued for natural gas fired combined-cycle power plants.

b. Facilities from the EPA Clearinghouse are identified with an EPA clearinghouse number, which is a two-letter state code followed by a four-digit number. All other facilities are from the CARB Clearinghouse.

The review of permit limits shows that most permitting agencies appear to be converging on a consensus of 2.0 ppm as BACT for CO, which is the BACT 2 "achieved in practice" level of control for this type of facility. There are also several facilities that have been permitted with permit limits less than 2 ppm, as shown in the table, but these facilities do not establish that lower limits have been achieved in practice. One of the three facilities with CO limits less than 2 ppm has not been built (CPV Warren) and another facility has been built but not operated (Kleen Energy), so there is no operational data available from either of these facilities to assess whether they are in fact able to achieve these permit limits. The third facility with a CO permit limit less than 2 ppm (McDonough) is operational, but this facility has a $NO_x$ limit that is much higher than 2 ppm (6 ppm) so this facility is not comparable to the LECEF combined-cycle units. For combustion sources $NO_x$ and CO emissions typically have an inverse relationship, with CO increasing as NOx emissions are reduced. Having a higher $NO_x$ limit of 6 ppm makes it possible to keep CO emissions at lower levels, but the District prioritizes NOx reductions over CO reductions because the Bay Area is in compliance with CO air quality standards but not in compliance with ozone standards. (NOx is a precursor to ozone formation.) CO emissions below 2.0 ppm have not been achieved in practice for facilities with low NOx limits like the 2.0 ppm BACT limit that the District is imposing here. In addition, the McDonough facility's limit uses a

3-hour averaging period, making it easier to comply with than the more stringent 1-hour averaging period the District is imposing here. With a longer averaging time, short-term high-emissions fluctuations can be offset by other times during the averaging period with low emissions. A facility with a lower limit using a 3-hour averaging period therefore does not establish that the lower limit could be achieved with the more stringent 1-hour averaging period the District is requiring here.

The District also considered whether it would be technically feasible and cost-effective to require the LECEF Phase II project to meet an emissions limit below the 2.0 ppm achieved for similar combined-cycle facilities. This "BACT 1" analysis found that using a larger oxidation catalyst might be capable of meeting a CO permit limit below 2 ppm, although doing so could have additional implementation problems such as high back-pressure, which could adversely impact turbine operating performance and efficiency. In any event, even if achieving a limit below 2.0 would be technically feasible, it would not be cost-effective to do so under the District's BACT cost-effectiveness guidelines given the large costs involved.

The District reviewed information on the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining CO emissions below 1.5 ppm.[28] Based on three vendor estimates, the approximate cost of achieving a 1.5 ppm permit limit would be an additional $136,680 for the equipment (above what it would cost to achieve a 2.0 ppm limit) and a total annualized operating cost of $108,851.[29] The additional reduction in CO emissions would amount to approximately 9.8 tons per year, which results in an incremental cost-effectiveness value of approximately $11,100 per ton of additional CO reduction.[30] Additionally, the total annualized costs of achieving a 1.5 ppm CO limit, calculated in accordance with EPA guidelines, would be approximately $507,523 per gas turbine, and the resulting emission reduction from the baseline emissions of 10 ppm CO would amount to 41.7 tons per year, resulting in a total (or "average") cost effectiveness value of over $12,200.[31] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.5 ppm CO permit limit cannot reasonably be justified as a BACT limit.[32]

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[28] A potential lower limit of 1.5 ppm provides a reasonable basis for this analysis because that number is in the middle of the range of permit limits below 2.0 found in the other permits the Air District reviewed. Given that the results of the cost-effectiveness analysis for a 1.5 ppm limit are well above what has been required at other similar facilities to achieve CO reductions, there is no reason to believe that any other limits below 2.0 ppm would be cost-effective for purposes of the BACT analysis.

[29] See vendor quotations from CMI Groupe, Nooter/Ericksen, Inc., Deltak, and Foster Wheeler.

[30] *See* Spreadsheet, Incremental Cost Effectiveness Analysis for CO Control From 2 to 1.5 ppmv, prepared by Barbara McBride, Calpine Corp., reviewed and amended by Weyman Lee, P.E., BAAQMD.

[31] *See* McBride, Calpine Corp., reviewed and amended by Weyman Lee, P.E., BAAQMD.

[32] The Air District has not adopted its own cost-effectiveness guidelines for CO, but a review of thresholds used by other agencies and specific BACT determinations by the District and others shows that additional CO reductions are not normally required as BACT where they would cost more than a few hundred to a few thousand dollars per ton. (*See* South Coast Air Quality Management District, Best Available Control Technology Guidelines, August 17, 2000, revised July 14, 2006, at 29; available at: www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power, Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit

Based on the foregoing analysis, the ATC's limit on CO of 9 ppm should be reduced to 2 ppm, averaged over one hour, to meet current BACT requirements.

### III.A.3. Sulfur Dioxide ($SO_2$)

When the District issued the initial Phase II ATC, it evaluated BACT for $SO_2$ and determined that BACT required the use of clean-burning natural gas with a sulfur content not to exceed 1 gr/100 scf. The District has reviewed this BACT limit and found that it continues to satisfy current BACT standards. The District's BACT Guideline for this source category (Guideline 89.1.6) has not been revised since the initial Phase II ATC was issued, the standards for sulfur content in natural gas have not changed, there are no new control technologies that can feasibly be used to remove $SO_2$ from the emissions stream,[33] and the District has not found any other similar facilities that are using any better technologies. The District has therefore determined that current BACT for $SO_2$ for the combined cycle gas turbines is the exclusive use of the highest quality commercially available natural gas that meets the PG&E Gas Rule 21, Section C standard of less than 1.0 grains of sulfur per 100 scf.

The District also included an hourly numerical $SO_2$ mass emissions limit in the initial Phase II permit, although the numerical limit was not the basis for the BACT determination. The District has now determined that a numerical mass emissions limit is not appropriate as a permit limit for a pollutant such as $SO_2$. There are no add-on control technologies that are effective to reduce $SO_2$ emissions from a facility such as this, and $SO_2$ emissions are therefore not within the control of the operator beyond ensuring that low-sulfur fuel is burned. For this reason, there is no air quality benefit that would be gained from imposing a numerical emissions limit as BACT. Unlike other criteria pollutants such as NOx or CO, where the operator can design and operate its equipment and control systems to meet the applicable permit limit, $SO_2$ emissions will be what they will be based on fuel sulfur content and turbine combustion dynamics regardless of what actions the operator takes. Imposing a numerical mass limit as a permit condition therefore makes no difference from an operational perspective regarding what level of the emissions the facility will produce, and no difference in terms of the facility's impact on ambient air quality. Furthermore, a numerical mass emissions limit is not required by the BACT regulation. District regulation 2-2-206 defines BACT as either a "control device or technique" (Sections 2-2-206.1 and -206.3) or an "emission limitation" (Section 2-2-206.2 and -206.4), and does not require that

issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005; BAAQMD Application No. 15487, Russell City Energy Center, Responses to Public Comments (Feb. 3, 2010), pp. 69-74; EPA Region 4, "National Combustion Turbine List," available at: www.epa.gov/region4/air/permits/national_ct_list.xls.) The costs per ton of additional reductions here would exceed these levels by a significant amount.

[33] Wet scrubbing and dry scrubbing technologies used at facilities combusting high-sulfur-content fuels are not feasible for combustion sources burning low-sulfur-content natural gas. The $SO_x$ concentrations in the natural gas combustion exhaust gases are too low (less than 1 ppm) for the scrubbing technologies to work effectively or be technologically feasible or cost effective. These control technologies to remove sulfur in the exhaust are not feasible as a control technology for natural gas turbines.

both be imposed as permit requirements. As long as the most stringent control device or technique is required, BACT does not require a mass emissions limitation to be imposed as well through permit conditions where (as here) it is not warranted from an air quality perspective. For these reasons, the District is not intending to include a numerical $SO_2$ mass emissions limit in the renewed permit.

### III.A.4. Particulate Matter (PM)

As with $SO_2$, the District's initial Phase II ATC evaluation determined that BACT for $PM_{10}$ required the use of clean-burning natural gas with a sulfur content not to exceed 1 gr/100 scf.[34] The District has reviewed this analysis and has determined that it continues to meet current BACT requirements. The District's BACT Guideline for this source category has not been revised since the initial Phase II ATC was issued,[35] the maximum sulfur content in natural gas has not changed, and there are no new control technologies that can feasibly be used to remove $PM_{10}$ from the emissions stream.[36] The District has therefore determined that use of a

[34] *See* Final Determination of Compliance, Los Esteros Critical Energy Facility, Plant 13289, Combined-Cycle Conversion (Phase II), dated June 28, 2005, page 22. Clean burning natural gas was defined as a maximum sulfur content of 1.0 gr/100 scf.

[35] In addition, the California Air Resources Board's guidance on PM emissions from power plants has also not been revised since the initial ATC was issued, and continues to be consistent with the District's BACT determination. *See* Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999, pg. 34.

[36] Add-on control devices such as electrostatic precipitators and baghouses are not achieved-in-practice for natural gas fired combustion turbines and are not technically feasible here. These devices are normally used on solid-fuel fired sources or others with high PM emissions, and are not used in natural gas fired applications which have inherently low PM emissions. The District is not aware of any natural gas fired combustion turbine that has ever been required to use add-on controls such as these. The District also reviewed the EPA BACT/LAER Clearinghouse and confirmed that EPA has no record of any post-combustion particulate controls that have been required for natural gas fired gas turbines. The District has therefore determined that these control devices are not achieved in practice for this type of facility. Furthermore, if add-on control equipment was installed it would create significant back pressure that would significantly reduce the efficiency of the plant and would cause more emissions per unit power produced. Also, these devices are designed to be applied to emissions streams with far higher particulate emissions, and they would have very little effect on the low-PM emissions streams from this facility in further reducing PM emissions. (For example, if a baghouse were installed on the turbines, the turbine exhaust at the *inlet* to the baghouse would contain less PM than is normally seen in baghouse *output*, after abatement. PM emissions from a baghouse are normally in the range 0.0013 to 0.01 grains per standard cubic foot (*see BAAQMD BACT/TBACT Workbook*, Section 11: Miscellaneous Sources), whereas PM emissions from the proposed LECEF turbines would be 0.0012gr/dscf.) It takes an emissions stream with a much higher grain loading for these types of abatement devices to operate efficiently. This low level of effectiveness (if any) also means that these types of control devices would not be cost-effective, even if they could feasibly be applied to this type of source. For all of these reasons, post-combustion particulate control equipment is not technologically feasible/cost effective for the LECEF turbines.

high-efficiency inlet air filter and low-sulfur natural gas with good combustion practice are the BACT control technologies for the proposed LECEF Phase II project. For low-sulfur fuel, the highest quality commercially available natural gas is natural gas that meets the PG&E Gas Rule 21, Section C standard of less than 1.0 grains of sulfur per 100 scf. This PG&E standard is maximum sulfur content at any point in time.[37] Good combustion practice for the proposed gas turbines at LECEF Phase II includes maintaining the combustion system to minimize incomplete combustion,[38] optimizing efficiency to minimize fuel usage, and onsite visual tools for monitoring combustion dynamics and performing diagnostics.

The District has also determined that the $PM_{10}$ hourly numerical emissions limits that were included in the initial ATC are not warranted under the BACT requirement, for similar reasons to those discussed in connection with the $SO_2$ BACT analysis above. The District's BACT regulations require the District to implement BACT either as a control device or technique (Regulation 2-2-206.1 and 2-2-206.3) or as an emission limitation (Regulation 2-2-206.2 and 2-2-206.4), and do not require both types of BACT limits. The control techniques described above will fulfill the BACT requirement for PM in accordance with Regulations 2-2-206.1 and 2-2-206.3. The District has concluded that imposing a numerical emissions limit, in addition to requiring BACT technologies, would not be warranted given that there are no add-on control devices that the facility can use to control PM emissions. Assuming the facility is using good combustion practices, PM emissions will be determined by the amount of sulfur in the fuel and the way that the combustion equipment functions, which are factors that are not within the control of the operator. PM therefore presents a different situation than other pollutants such as NOx or CO where the project owner can design its add-on control systems to achieve the required level of emissions and ensure that it will comply with its emission limits by operating the add-on control systems properly. For these reasons, the District does not intend to include numerical hourly $PM_{10}$ limits in the renewed ATC.

This BACT determination is consistent with guidance from the California Air Resources Board in setting BACT for natural gas-fired gas turbines.[39] This BACT determination is also consistent with District BACT Guideline 89.1.6, which specifies BACT for $PM_{10}$ for combined-cycle gas turbines with rated output of $\geq$ 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf.[40] These guidance documents do not suggest that a numerical emissions limit should be required as a BACT permit condition.

[37] PG&E's Gas Rule 21, Section C requires the quality of gas received into the pipeline system to have a maximum sulfur content of 1.0 grain per 100 scf. The average content is expected to be less than 0.25 grains per 100 scf. The District has based its calculations of annual emissions on this 0.25 grain per 100 scf average sulfur content. Note that a portion of the sulfur contained in natural gas is intentionally added as an odorant to allow for the detection of leaks which would be a safety concern. PG&E Gas Rule 21, Section C can be found at: http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml.

[38] Unburned hydrocarbons from the natural gas that are not fully combusted may condense to form PM. Permit conditions limit the CO emissions to 2 ppm over a 1-hour averaging period. This high level of control of CO indicates unburned hydrocarbons are also well controlled, thereby minimizing PM emissions. Good combustion practice will be ensured by the use of a CEM to monitor CO emissions. Compliance with the stringent CO emissions limits in the permit indicates that good combustion practices are being implemented.

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

[40] *See* Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm

### III.A.5. Precursor Organic Compounds (POC)

The initial Phase II ATC included a POC limit of 2.0 ppm (3-hour average). The District has reviewed this limit and has determined that current BACT requires a POC limit of 1.0 ppm (1-hour average). This determination is based on a review of permit limits and emissions test data from similar facilities.

The District reviewed permit limits from similar facilities to determine the appropriate POC permit limit for the LECEF Phase II combined-cycle gas turbines, which are summarized in Table 6 below.

**Table 6: Recent BACT $NO_X$ and POC Permit Limits for Large Combined-Cycle Turbines**

| Facility | Date | $NO_x$ ppmvd@15%$O_2$ | POC Emissions Limit |
|---|---|---|---|
| Goldendale Energy Project, WA-00302 | 2/2001 | 2 (3-hr) | 6 ppm (1-hr) |
| Sumas Energy 2, WA-0315 | 4/2003 | 2 (3-hr) | 420 lb/day (6.4 ppm (24-hr)) |
| Sierra Pacific Power Company, Tracy Station, NV-0035 | 8/2005 | 2 (3-hr) | 4.0 ppm (3-hr) |
| Rocky Mountain Energy Center, CO-0056[a] | 5/2006 | 3.0 (1-hr) | 0.0029 lb/MMBtu (2.3 ppm) |
| Wellton Mohawk, AZ-0047 | 12/2004 | 2 (3-hr) | 3 ppm (3-hr) |
| Elk Hills, SJVAPCD | 2000<br>2003 | 2.5 (1-hr) | 2 ppm (3-hr) |
| Palomar Energy Project, SDAPCD | 8/2003<br>4/2006 | 2 (1-hr) | 2 ppm (3-hr) |
| Morro Bay – Duke, SLOAPCD | 8/2004 | 2 (1-hr) | 2 ppm (3-hr) |
| San Joaquin Valley Energy Center, SJVAPCD | 1/2004 | 2 (1-hr) | 2 ppm (3-hr) |
| Three Mountain, Shasta County | 1999 | 2.5 (1-hr) | 2 ppm (1-hr) |
| Magnolia, SCAQMD | 5/03 | 2 (3-hr) | 2 ppm (1-hr) |
| Colusa Generating Station, CCAPCD | 4/2008 | 2 (1-hr) | 2 ppm (1-hr) |
| Carlsbad Energy Center | TBD | 2 (1-hr) | 2 ppm (1-hr) Normal<br>2 ppm (3-hr) Transient |
| Delta Energy Center, BAAQMD | 2/2000<br>5/2002 | 2.5 (1-hr) | 5.33 lb/hr or 0.00251 lb/MMBtu (2 ppm) |
| La Paloma, SJVAPCD | 12/2000<br>2003 | 2.5 (1-hr) | 0.7 (3-hr) as Propane<br>1.9 (3-hr) as Methane |
| Southern Company McDonough | 1/2008 | 6 (May 1 to Sept 30) | 1.8 ppm (3-hr) Duct Firing |

**Table 6: Recent BACT $NO_X$ and POC Permit Limits for Large Combined-Cycle Turbines**

| Facility | Date | $NO_x$ ppmvd@15%$O_2$ | POC Emissions Limit |
|---|---|---|---|
| Combined Cycle, GA-0127 | | 15 (Remainder), 30 day Rolling Average | 1.0 ppm (3-hr) No Duct |
| SMUD Clay Station, SMAQMD | | 2 (1-hr) | 1.4 ppm (3-hr) |
| Sunset Power, SJVAPCD | 12/2003 | 2 (1-hr) | 1.4 ppm (3-hr) |
| Sacramento Municipal Utilities District, Consumnes | 9/2003<br>2/2006 | 2 (1-hr) | 1.4 ppm (3-hr) |
| ANP Blackstone, MA-0024 | 4/1999 | 2 (1-hr) No Steam Inj.<br>3.5 (1-hr) Steam Injection | 1.4 ppm (1-hr) no steam<br>3.5 ppm (1-hr) steam inj. |
| Los Medanos Energy Center, BAAQMD | 1999<br>2001 | 2.5 (1-hr) | 3.8 lb/hr or 0.0017 lb/MMBtu (1.4 ppm) |
| Mountainview<br>San Bernardino County | 3/2001<br>12/2005 | 2.5 (1-hr)<br>Lowered to<br>2.0 (1-hr) in 2005 | 3.47 lb/hr<br>(0.00163 lb/MMBtu)<br>(1.3 ppm) |
| FPL Turkey Point, FL-0263 | 2/2005 | 2 (24-hr) | 1.3 ppm (UNK) No Duct<br>1.9 ppm Duct Firing |
| CPV Warren, VA-0308 Scenario 1<br>GE Frame 7FA | 1/2008 | 2 (1-hr) | 0.7 ppm (3-hr) No Duct<br>1.0 ppm (3-hr) Duct Firing<br>1.4 ppm (3-hr) Power Aug. |
| CPV Warren, VA-0308 Scenario 2<br>GE Frame 7FA | 1/2008 | 2 (1-hr) | 0.7 ppm (3-hr) No Duct<br>1.0 ppm (3-hr) Duct Firing |
| CPV Warren, VA-0308 Scenario 3<br>Siemens STG6-5000F | 1/2008 | 2 (1-hr) | 0.7 ppm (3-hr) No Duct<br>1.4 ppm (3-hr) Duct Firing |
| CPV Vaca Station, YSAQMD<br>Siemens SGT6 5000F or<br>GE Frame 7FA | TBD | 2 (1-hr) | 2 ppm (1-hr) |
| Turner Energy Center, OR-0046 | 1/2005 | 2.0 (1-hr) | 1 ppm (3-hr) |
| Calpine Facility, Feather River AQMD | 12/2000 | 2.5 (1-hr) | 1 ppm (24-hr) |
| IDC Bellingham, MA | 9/2000 | 1.5/2.0 (1-hr) | 1 ppm (1-hr) |
| Metcalf Energy Center, BAAQMD | 2001<br>2005 | 2.5 (1-hr) | 2.7 lb/hr or 0.00126 lb/MMBtu (1 ppm) |
| Russell City Energy Center, BAAQMD | 2010 | 2 (1-hr) | 2.86 lb/hr or 0.00128 lb/MMBtu (1 ppm) |

Notes:

a. Information presented is from a database search of a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse for recent permits issued for natural gas fired combined-cycle power plants

b. Facilities from the EPA Clearinghouse are identified with an EPA clearinghouse number, which is a two-letter state code followed by a four-digit number. All other facilities are from the CARB Clearinghouse.

This review shows a number of facilities with limits of 1.0 ppmvd @ 15% $O_2$ averaged over one hour. Within the District's jurisdiction, the Metcalf Energy Center has been meeting this permit limit with an oxidation catalyst for over a year and demonstrates that this level of emissions reduction can be achieved for this type of facility.[41]

Table 6 also shows one facility, the CPV Warren plant, with a permit limit of 0.7 ppm for turbine-only operation (no duct firing), and so the District considered whether current BACT should be set at 0.7 ppm. The District notes that the CPV Warren plant has not been built at this time, and there is no operational data indicating whether this limit is actually achievable. This permit does not establish that the limit has actually been achieved in practice.

The District nevertheless considered whether it would be technologically feasible and cost-effective to impose a POC limit at this level. The District has concluded that even if it would be technically feasible to achieve 0.7 ppm, it would not be cost-effective to do so given the high costs involved. The District calculated the cost effectiveness of installing a larger oxidation catalyst designed to maintain POC emissions below 0.7 ppm (1 hour average).[42] Based on the costs and emissions reduction benefits of these analyses, the cost of achieving a 0.7 ppm permit limit would be an additional $108,851 per year (above what it would cost to achieve a 1.0 ppm limit), and the additional reduction in POC emissions would be approximately 0.8 tons per year, making an incremental cost-effectiveness value of $132,700 per ton of additional POC reduction.[43] Moreover, the total cost of achieving a 0.7 ppm POC limit (as opposed to the incremental costs of going from 1.0 ppm to 0.7 ppm) would be over $507,523 per year, and the total emission reductions from 2.0 ppm from the turbine to a 0.7 ppm limit would be 3.6 tons per year, resulting in a total (or "average") cost-effectiveness value of $140,200 per ton.[44] The District has adopted guidelines that establish that the maximum cost that the District will require a facility to bear to reduce POC emissions under the BACT requirement is $17,500 per ton.[45] Based on the high costs (on a per-ton basis) and the relatively little additional POC emissions benefit to be achieved (on a per-dollar basis), requiring a 0.7 ppm POC permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 0.7 ppm limit would be substantially more expensive, on a per-ton basis, than what other similar facilities are required to achieve.

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[41] The District also considered whether there were any additional control technologies available to reduce POC emissions. Like CO emissions, POC emissions are a product of incomplete combustion, and so technologies that are effective to reduce CO emissions will also be effective to reduce POC emissions. The BACT technology review for CO is therefore also applicable to POC. As noted above in the discussion of CO, the facility will use an oxidation catalyst and there are no other more effective control technologies available.

[42] See vendor quotations from: (1) Vijay Patel, Deltak email to Paul Prusi, Calpine re Los Esteros Permitting, on March 17,2010; (2) Larry Oprea, Foster Wheeler email to Paul Prusi, et al (Calpine) re Los Esteros Emissions, on March 23, 2010; (3) Mike Filla, Nooter-Ericksen email to Paul Prusi, Calpine re Urea SCR Catalyst System on November 11, 2009; (4) Craig Smith, CMI Groupe email to Paul Prusi, Calpine re CO Catalyst Costs on April 8, 2009.

[43] *See Spreadsheet LECEF POC Cost Effectiveness Incremental.*

[44] *See Spreadsheet LECEF POC Cost Effectiveness full to 0.7.*

[45] *See* Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

The District has therefore determined that BACT for POC for this facility is the use of good combustion practice with abatement by an oxidation catalyst for each gas turbine with a permit limit of 2.71 lb per hour, which corresponds to 1.0 ppmvd @ 15% $O_2$. Compliance with the POC permit limits will be demonstrated by annual source tests.

Based upon the results of this analysis, the District concludes that the POC emission limit should be reduced to 1.0 ppmv @ 15% $O_2$.

### III.A.6. Startup and Shutdown Emissions

The initial Phase II ATC included a limit on turbine startups of 240 minutes and a limit on turbine shutdowns of 30 minutes. The District has reviewed these limits and has concluded that current BACT would require shorter time limits on startups, as explained in detail below. In addition, the District has also decided to include numeric mass emission limits for emissions during startups and shutdowns as it has done with other recent power plant permits. The District's analysis is set forth in the following paragraphs.

### III.A.6.i. – Turbine Startups

Emissions during startups are higher than during normal steady-state operation for several reasons. One reason is that the turbines are not operating at full load where they are most efficient. Another reason is that turbine exhaust temperatures are lower than during steady-state operation, and post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function with full efficiency at these lower temperatures. The District evaluated the extent to which the facility could feasibly minimize startup emissions to ensure that it meets current BACT standards.

- ***Startup Control Technologies:***

First, the District reviewed what control devices or techniques would be required by BACT to control startup emissions. The existing startup limits were based on using best work practices designed to minimize the amount of emissions that occur during startups. This is accomplished by optimizing the start-up sequence so that the unit reaches the point when its emissions control technologies are functioning at an optimal level with the least emissions possible. This was the only startup emissions control technique that was available at the time the District issued the initial Phase II ATC.

To determine whether this analysis still meets current BACT, the District reviewed additional emerging technologies that have been developed recently that can further reduce startup emissions from large combined-cycle facilities. The District examined the recently-developed "Fast Start" technology, which uses an integrated plant design that bypasses the steam turbine during startups so that the facility can come up quickly while the steam turbine is still coming up to operating temperature. Bypassing the steam turbine in this way avoids the main reason for the higher startup emissions for conventional combined-cycle technology, which result from the additional time it takes for the steam turbine to warm up. This technology is marketed by GE under the name "Rapid Response" and by Siemens under the name "Flex Plant". The District also examined low-load "turn-down" technology, which helps the turbine keep emissions low at low operating load and therefore could potentially benefit startup emissions since startups involve some low-load operation as the turbine is ramping up to full load. This technology is marked by GE under the name "Op-Flex".

These emerging technologies were developed primarily for larger frame/utility-size turbines, however, and not for the smaller aeroderivitive turbines like those used at the LECEF facility. Aeroderivitive turbines like the LM6000s at LECEF are already designed for fast startup and shutdown times, and they are predominantly used in simple-cycle plants. In contrast, larger frame/utility turbines are predominantly used in combined-cycle plants that require additional time to startup (the HRSG and steam turbine in a combined-cycle plant extend the startup duration). Efforts to develop startup emissions control technologies have therefore focused on the frame/utility-size turbines where reducing startup times has the most impact. As a result, these technologies are currently not as well-developed in aeroderivitive applications, and are not available for use in the LECEF Phase II project.[46] More rudimentary fast-start type designs are available for LM6000 turbines, but these involve the use of a less-efficient single-pressure steam turbine system. The LECEF Phase II project will use a more efficient multi-pressure reheat steam turbine system. This multi-pressure reheat steam turbine will give the facility a higher overall efficiency, which results in less fuel consumption, lower greenhouse gas emissions, and lower criteria pollutants per unit of power output during steady-state operation. These efficiency gains will provide benefits during all periods of operation, not just during startups, and so it is less preferable to require a single-pressure system even if it could provide some measure of startup benefit. The District has therefore concluded that there are no recent developments in startup control technologies that would be available for use with the LECEF Phase II project, and thus that best work practices is still the BACT control technique.

- ***Startup Limits:***

To determine appropriate BACT emission limits for startups, the District evaluated what startup emissions have been achieved in practice and what can feasibly be achieved for this project. Aeroderivitive turbines such as the LM6000s at this facility are most often used in simple-cycle peaking applications, and so the District did not find many similar facilities to which to compare this project. The one similar facility with startup limits that can be used to compare with this project is the Donald Vonraesfeld power plant in Santa Clara, CA. That facility uses combined-cycle LM6000 turbines, and is achieving startup emission limits of 41 pounds of NOx, 35 pounds of CO and 2 pounds of POC per startup, with startup duration not to exceed 180

[46] *See* Letter from Eddy Wacek (LM6000 Business Operations Manager, GE Power & Water, Aero Energy) to Mitchell D. Weinberg (Director, Project Development, Calpine), May 19, 2010 at 1 ("The OpFlex suite of flexibility products is designed for GE's Heavy Duty (Frame) Gas Turbines and not the Aeroderivitive Gas Turbines. Aeroderivitive technology is, by its nature, highly flexible and already incorporates many of the features offered for GE's Heavy Duty Gas Turbines OpFlex products."); *see also id.* at 2 ("Rapid Response is a patented, integrated combined cycle system for the GE's Heavy Duty Gas Turbine power plants. It is designed to allow faster starting of the overall plant, coupled with faster starting of the gas turbines. Rapid Response is not currently offered for Aeroderivatives because their inherent flexibility, size, and relative exhaust temperature already allows for Aeroderivative plant designs with greater overall responsiveness"); *see also* telephone note of conversation between Weyman Lee and Ben Beaver, Siemens Corp. on August 30, 2010 re the availability of "Flex Plant" technology for aeroderivative turbines.

minutes.[47] These startup limits are achieved in practice for purposes of BACT, and the LECEF Phase II project will be required to meet limits at least as stringent as these.

The District then evaluated startup data from the existing Phase I simple-cycle project, with an extrapolation from that data presenting an estimate what startup emissions could be achieved when the facility is converted to combined-cycle operation. Startups for the combined-cycle mode will require the turbine to be held at about 40% load for approximately 40 minutes to allow the HRSG to warm up and to initiate the steam cycle. In addition, it will take approximately 30 minutes for the SCR system to warm up to a sufficiently high operating temperature for ammonia injection to commence, and then approximately 10 minutes after that the SCR system to become fully effective. During that 10-minute period of early ammonia injection, the SCR system will be operating at only around 60% NOx reduction. When the turbine reaches the end of its 40-minute low-load hold period, it will then start to ramp up to full desired load, which will be reached after approximately 70 minutes. At that point, NOx emissions will be relatively low but will fluctuate somewhat as the SCR system settles into balance and begins to achieve optimal performance. The system is expected to be able to achieve compliance with the steady-state NOx limit of 2.0 ppm by 120 minutes into the startup under this analysis.[48]

This analysis of the emissions that would be involved during startups estimated what emissions rates would be minute-by-minute during the entire 120-minute startup period. Aggregating the minute-by-minute emissions projections, the analysis estimates that total emissions from the entire startup would be 40.2 pounds of NOx.[49] This analysis shows that the LECEF Phase II project should be able to meet the same 41-pound emission limit that is achieved-in-practice based on the Donald Vonraesfeld facility. A 41-pound NOx limit for startup emissions would leave very little compliance margin over the District's projection based on the analysis from the Phase I data, but Calpine has committed to ensuring that emissions do not exceed this level using NOx control techniques such as commencing ammonia injection at the earliest possible time during the startup and maximizing the use of water injection to keep NOx emissions as low as possible. The District has determined that Calpine should reasonably be able to comply with the 41-pound limit using these measures.

For CO, the startup emissions analysis shows that the LECEF Phase II project should be able to achieve startup emissions substantially below the 35 pounds that the Donald Vonraesfeld facility is achieving. The startup analysis predicts emissions of 18.4 pounds of CO per startup.[50] Based on this analysis, the District has concluded that a not-to-exceed permit limit of 20 pounds per startup represents the most stringent permit limit that will be consistently achievable. A permit limit of 20 pounds provides a small compliance margin to ensure that the limit will be achievable in the event that the startup analysis the District relied on turns out to be an under-estimate.

For POC, there is little operational data available from the LECEF Phase I operation because POC emissions are not recorded with CEMs. The District was therefore not able to obtain an

[47] *See* BAAQMD permit for Silicon Valley Power Von Raesfeld Power Plant, Site No. B4991, Condition No. 24252.

[48] *See* spreadsheets, "LECEF Mock Startup NOx 10-29-2010" and , "LECEF Mock Startup Event CO 10-29-2010". These spreadsheets are based on actual startup operating data from the LECEF Phase I simple-cycle facility, with estimates made about how the equipment would operate after conversion to combined-cycle operation.

[49] *See* spreadsheet, "LECEF Mock Startup NOx 10-29-2010".

[50] *See* spreadsheet, "LECEF Mock Startup Event CO 10-29-2010".

estimate of POC performance based on extrapolating from operational data as it did with NOx and CO. Instead, the District is basing its POC BACT limit for startups on the 2-pound emissions limit achieved by the Donald Vonraesfeld facility. The NOx and CO data that the District evaluated for the LECEF Phase II project show that startup emissions from this project will generally be consistent with what the Donald Vonraesfeld facility is achieving, and at 2 pounds of POC the limit for that facility is very stringent. The District is therefore recommending a 2-pound POC limit as BACT for startups.

Finally, the District also considered whether to have separate limits for different startup situations as has been done in other power plant permits, which for example delineate different limits for cold startup and hot or warm startups. Separate limits are not required under BACT, but can be appropriate where circumstances warrant different treatment for different startup scenarios. The District has not found any evidence that there will be any substantial difference in emissions from different startup situations for the LECEF Phase II project. One of the main differences between cold startups and hot or warm startups at other facilities is that for cold startups, the combustion turbine needs to be held at low load for a longer time with cold startups because it takes longer to heat up the steam turbine. The combustion turbine cannot be ramped up to full load as quickly because full load generates more steam for the steam turbine, and as the steam turbine is warming up it cannot handle full steam output without excessive thermal stresses. For the LECEF Phase II project, however, some of the steam that is generated can be vented and not sent to the steam turbine, minimizing the delay in the combustion turbine coming up to full load. For this reason, the delays associated with cold startups are not expected to be any longer than those associated with hot or warm startups, and emissions are not expected to be substantially different. Moreover, the similar Donald Vonraesfeld power plant does not differentiate between different startup scenarios, and the startup limits the District is contemplating here would be consistent with the permit for that facility.

Based on this analysis, the District is recommending numerical emissions limits of 41 pounds of NOx, 20 pounds of CO, and 2 pounds of POC per startup. The District is also recommending lowering the limit on startup duration to 120 minutes. These permit conditions would be consistent with current BACT standards.

### III.A.6.ii. – Turbine Shutdowns

For shutdowns, best work practices remains the only way to minimize emissions. There are no additional technologies that can shorten shutdowns or otherwise reduce shutdown emissions. For combined-cycle facilities, shutdowns can take up to 30 minutes because the combustion turbine must be ramped down slowly so as to prevent the steam-cycle equipment from being damaged by being cooled too rapidly (thermal shock). The District reviewed recent permits issued for combined-cycle facilities, and none have found that shutdowns could be accomplished in less than 30 minutes. During this shutdown period, the facility will not be able to achieve the very low NOx, CO and POC emission concentrations that it will achieve during stead-state operations because it will not be operating at normal loads where emissions performance is optimized. The turbines should be able to keep total emission rates (*i.e.*, the mass of pollutants emitted) within the rates for steady-state operations, however. These hourly rates are 4.6 lb/hr of

NOx, 2.85 lb/hr of CO, and 0.81 lb/hr of POC. The turbines will therefore need to be exempted from the steady-state BACT limits on concentration for these pollutants, but not for the BACT limits on mass emission rates. Emissions will continue to comply with the BACT steady-state emission rates during shutdown operations. These emission rates are more stringent than what is being achieved by the comparable Donald Vonraesfeld power plant, which has shutdown emissions limits of 8 lb/hr NOx, 10 lb/hr CO and 1 lb/hr POC.

Based on this analysis, the District has determined that the 30-minute limit on shutdown duration is consistent with current BACT requirements. The District is also imposing numerical emissions limits applicable during shutdowns of 4.6 lb/hr of NOx, 2.85 lb/hr of CO, and 0.81 lb/hr of POC.

## III.B. BACT for Six-Cell Cooling Tower

When the District issued the initial ATC, it determined that the proposed six-cell wet cooling tower was subject to BACT for $PM_{10}$ since its potential to emit exceeded 10 pounds per day for that pollutant, based on information that the District had at that time. The District therefore imposed BACT conditions in the initial Phase II ATC requiring the use of drift eliminators with a maximum guaranteed drift rate of 0.0005% and a limit on total dissolved solids (TDS) in the cooling water of not more than 10,000 ppmw (mg/l).

Based on information from other facilities regarding cooling water TDS levels, the District explored whether the LECEF Phase II project would be able to keep TDS at lower levels to reduce $PM_{10}$ emissions. TDS in the cooling water is a function of the TDS in the incoming water from the facility's water source and the number of times that the water is recycled through the cooling system. The District therefore evaluated the maximum TDS concentration in the water the facility has received from the City of San Jose water treatment plant over the last 4 years, which was 870 ppm as summarized in Table 7 below. Based on 6 cycles of concentration expected for LECEF, the resulting TDS value would be 6,000 ppmw.[51] Assuming that there may be some additional variability over the years, the District conservatively assumed that TDS could potentially be as high as 6,000 ppm, but would not reach the 10,000 ppm limit established in the initial ATC. With TDS kept below 6,000 ppm, and with drift eliminators with a maximum guaranteed drift rate of 0.0005%, total $PM_{10}$ emissions would be only 4.8 tons per year.[52] Based on this level of emissions, the cooling tower is exempt from permitting requirements under District Regulations 2-1-128.4 (cooling tower exemption) and 2-1-319 (5 tpy restriction on exemption).

[51] *See* email from B. McBride to W. Lee, dated 10/25/10, re Cooling Tower TDS Calculation Methodology. Cooling tower TDS is estimated by multiplying the recycled water TDS level by the cycles of concentration. A factor of 1.15 is also applied to account for the contribution from treatment chemicals and other makeup streams: 870 X 6 cycles X 1.15 = 6000.

[52] *See* cooling tower emissions calculations, Appendix A.

| **Table 7: City of San Jose Annual Average Recycled Water TDS Levels (**ppmw (mg/l))[53] | | | | |
|---|---|---|---|---|
| **Total Dissolved Solids** | **2007** | **2008** | **2009** | **2010** |
| **Average** | 711 | 733 | 720 | 741 |
| **Maximum** | 797 | 870 | 767 | 777 |

The District has therefore concluded that the six-cell cooling tower is in fact not subject to the BACT requirement in District Regulation 2-2-301. The District is keeping the 0.0005% drift rate drift eliminator requirement and a lowered TDS requirement of 6,000 ppm in the permit, however, to ensure that the $PM_{10}$ emissions remain below 10 pounds per day as an enforceable permit requirement.

## III.C. BACT for Commissioning Period

The process of converting the facility to combined-cycle operation will involve a number of highly complex steps in which the gas turbines and associated HRSGs are carefully tested, adjusted, tuned and calibrated to operate in accordance with the design expectations. These activities are referred to as "commissioning activities" and are defined in the Authority to Construct to include all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and construction contractor to ensure safe and reliable steady-state operation.[54] The current BACT permit limits for the Phase II conversion process require emissions to be minimized during the commissioning period requiring (i) completion of all commissioning activities in the shortest period of time possible and with the lowest emissions feasible; (ii) tuning of the gas turbines to minimize emissions of CO and nitrogen oxides NOx at the "earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor"; (iii) installation, adjustment and operation of the SCR systems and oxidation catalyst systems at the earliest feasible opportunity in accordance with the manufacturer and construction contractor recommendations; (iv) a limit on the total combined number of hours when any of the gas turbines and/or HRSGs may be operated without its respective SCR and oxidation catalyst systems to no more than 250 hours; (v) a restriction on operation of the gas turbines without abatement except for "discrete commissioning activities that can only be properly executed without the SCR or [oxidation catalyst] system in place"; and (vi) submission of a plan describing the procedures to be followed during commissioning, the anticipated duration of each activity in hours and the purpose of such activity.[55] The District has reviewed these conditions and has not found any area in which they could feasibly be made more stringent. The same considerations on which these conditions were based in the initial Authority to Construct continue to hold true at the present time. The District has therefore determined that the commissioning conditions in the initial Authority to Construct continue to represent BACT for commissioning activities. In particular, the District has reviewed the applicant's preliminary construction schedule, which identifies the various activities and their planned sequencing during

[53] *See* City of San Jose recycled water quality data at: http://www.sanjoseca.gov/sbwr/water-quality.htm.
[54] *See* definition of "Commissioning Activities", *infra* 36.
[55] *See id*, condition nos. 1 through 10, *infra 37 & 38*.

the commissioning period.[56] While preliminary in nature, this schedule identifies a subcategory of commissioning activities, which, together, amount to a total of 228 hours.[57] This estimate of the number of hours provided the basis for the limitation on total number of hours of operation of the gas turbines and HRSGs without abatement equipment installed. The 22 additional hours reflected by this condition represents a margin of less than 10%, which represents a reasonable tolerance for unexpected events that might occur during commissioning. Moreover, if the construction contractor should complete all activities which must be performed without emissions abatement in a shorter period of time than the anticipated 228 hours and/or the maximum of 250 hours provided by the ATC, the facility must then begin meeting the stringent BACT limits applicable to normal operations.

## IV. Emissions Calculations and Offsets Review

The second requirement for a renewal of an Authority to Construct under District Regulation 2-1-407.1.2 is that the facility must meet current emission offset requirements under District Regulations 2-2-302 and 2-2-303. These regulations require that the LECEF Phase II conversion project must provide Emission Reduction Credits (ERCs) to offset increases in emissions resulting from the project if such increases will be greater than specified threshold levels.

For the initial Authority to Construct for the Phase II conversion project, the District evaluated the amount of ERCs that the applicant would have to provide based on the permitted emissions increases allowed under the Authority to Construct. The District is now reevaluating the amount of ERCs that the applicant will need to provide based on the revised permit limits that will be included when the renewal is issued. The emissions calculations on which the District has calculated total facility emissions are set forth in Appendix A.

Regulation 2-2-302 requires that federally enforceable emission reduction credits must be provided for $NO_x$ and POC increases at a ratio of 1.15:1.0 and 1.0:1.0, respectively. Under the renewed ATC, the Phase II conversion project will increase annual $NO_x$ emissions from 74.9 tons to 95.2 tons, a 20.3 ton increase. At a ratio of 1.15:1.0, this increase requires 23.35 tons of ERCs to be provided. For POC, annual emissions will be decreasing when the Phase II conversion is implemented (from 21.0 tons to 12.3 tons), so no ERCs are required.

Pursuant to Regulation 2-2-303, emission reduction credits are required for $SO_2$ and $PM_{10}$ emissions only for facilities with $SO_2$ or $PM_{10}$ emissions that exceed 100 tons per year. The LECEF facility's emissions will be below these threshold levels (both under the current simple-cycle configuration and after the Phase II combined-cycle conversion), and so ERCs are not required to offset emissions of these pollutants. (Note however that the CEC has required the applicant to provide emission offsets for $SO_2$ as CEQA mitigation for the Phase II project.)

For CO, the Phase II conversion will not cause any increase in emissions, and the District's regulations would not require CO offsets even if there were any CO increase.

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[56] *See* Calpine Corp., Los Esteros Critical Energy Facility, Level 2 Summary Level Schedule, Rev 29, March 23, 2010, submitted by B. McBride (Calpine) to W. Lee (BAAQMD) on March 30, 2010.

[57] *See id*., sheet 4 of 4.

The ERCs required for the Phase II conversion project under the renewed ATC are summarized in Table 8 below.

**Table 8: Emissions Offsets Required (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) | 95.2 | 12.3 | 53.4 | 6.5 | 44.24 |
| Emission Increase (tpy) | 20.3 | (8.7) | (19.5) | 0.7 | 0.4 |
| Offset Ratio | 1.15:1.0 | 1.0:1.0 | N/A | N/A | N/A |
| Offsets Required (tpy) | 23.35 | 0 | 0 | 0 | 0 |

Calpine has surrendered ERCs from Certificate No. 1201 in the amount of 23.35 tons of NOx for this project. The submission of these ERCs satisfies current District offset requirements.

## V. Permit Conditions for Authority to Construct Renewal

Consistent with the analysis provided above, the District has determined pursuant to District Regulation 2-1-407.1 that the following permit conditions satisfy current BACT and offset requirements under District Regulations 2-2-301, -302, and -303 for the LECEF Phase II conversion project. The Permit Conditions are revised from the initial Authority to Construct for the Phase II project as shown below with deletions shown in ~~strikethrough~~ text, and inserts by underlined text.

**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 lesser of the first 120 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 19(a) and 19(c) and is in compliance with the emission limits contained in 19(a) through 19(d). |
| Gas Turbine Shutdown Mode: | The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(a) through 19(d) until termination of fuel flow to the Gas Turbine |
| Corrected Concentration: | The concentration of any pollutant (generally $NO_x$, CO or $NH_3$) corrected to a standard stack gas oxygen concentration. For ~~an~~ Gas Turbine 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~~of power to the grid~~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:

21. 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 48~~49~~ shall only apply after the commissioning period has ended. (basis: cumulative increase)
22. 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)
23. 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~~10, A-~~4~~12, A-~~6~~14 & A-~~8~~16) and OC Systems (A-~~1~~9, A-~~3~~11, A-~~5~~13 & A-~~7~~15) 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)
24. Coincident with the steady-state operation of SCR Systems (A-~~2~~10, A-~~4~~12, A-~~6~~14 & A-~~8~~16) and OC Systems (A-~~1~~9, A-~~3~~11, A-~~5~~13 & A-~~7~~15) 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)
25. 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)

26. 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. <u>If necessary to ensure that accurate data is collected at all times, the owner/operator shall install dual span emission monitors.</u> (basis: cumulative increase)

27. 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. <u>If necessary to ensure accurate data is collected at all times, the owner/operator shall install dual-span monitors.</u> (basis: BAAQMD 9-9-501, BACT, offsets)

28. 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 <u>for each power train</u> 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)

29. 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)

30. 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)

31. 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:**

32. <u>Consistency with Analyses</u>: 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)

33. 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)

34. 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)

35. 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)

36. 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)

37. 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)

38. 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 6-1-301; SIP 6-301)

39. 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; and shall not exceed 4.68 lb/hour (1-hour rolling average) except during periods of gas turbine startup 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~~ 5 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~~ Regulation 2-5)

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~~2.0 ppmvd @ 15 % $O_2$ (~~3~~1-hour rolling average), except during periods of start-up or shutdown as defined in this permit; and shall not exceed 2.85 lb/hr (1-hour rolling average) except during periods of start-up 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~~ 1 ppmvd @ 15% O2 (~~3~~1-hour rolling average), except during periods of gas turbine start-up or shutdown as defined in this permit; and shall not exceed 0.81 lb/hr (1-hour rolling average) except during periods of start-up 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.~~

~~40.~~ Turbine Start-up: The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up do not exceed the limits established below. (Basis: BACT, Cumulative increase)~~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)~~

| | Duration (Minutes) | NOx (lb/Event) | CO (lb/event) | POC (lb/event) |
|---|---|---|---|---|
| Start-Up | 120 | 41 | 20 | 2 |

41. 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~~175.6 | ~~1,009.6~~702.4 | ~~99~~94.1 |
| POC | ~~80.2~~20.2 | ~~320.8~~80.8 | ~~28.3~~12.3 |
| CO | ~~417.2~~97.0 | ~~1,668.8~~388.0 | ~~98.5~~53.4 |
| SOx (as $SO_2$) | ~~41.6~~ | ~~166.4~~ | ~~8.48.~~56.43 |
| $PM_{10}$ | ~~60~~ | ~~240~~ | ~~43.8~~38.5 |
| $NH_3$ | ~~198~~104 | ~~792~~416 | ~~118~~56.9 |

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 with the daily limits 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. The annual mass limits are based upon a rolling 8,760-hour period ending on the last hour. Compliance with the annual limits for NOx, POC, and SOx shall be demonstrated in the same manner as for the daily limits. Compliance with the annual emissions limits for $PM_{10}$ and $SO_2$ from each gas turbine shall be calculated by multiplying turbine fuel usage times an emission factor determined by source testing of the turbine conducted in accordance with Part 26. The emission factor for each turbine shall be based on the average of the emissions rates observed during the 4 most recent source tests on that turbine (or, prior to the completion of 4 source tests on a turbine, on the average of the emission rates observed during all source tests on the turbine). (Basis: cumulative increase, recordkeeping)

24. 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~~Regulation 2-2-306)

43. 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:

d. 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: | 12,000 MM BTU/day | 15,336 MM BTU/day |
| Four Turbine/HRSG Power Trains combined: | | 18,215,000 MM BTU/year |

e. 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. To demonstrate compliance with this sulfur content limit, the owner/operator shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas, in addition to any monitoring requirements specified in Paragraph 29. (Basis: BACT for $SO_2$ and $PM_{10}$.)

f. 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)

44. 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).

45. 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. Natural gas consumption, fuel High Heating Value (HHV), and total fuel sulfur content

g. Turbine load in megawatts

h. Stack gas flow rate (DSCFM) calculated according to procedures in U.S. EPA Method 19

i. Exhaust gas temperature (°F)

j. Ammonia injection rate (lb/hr or moles/hr)

k. Water injection rate for each turbine at S-1, S-2, S-3, & S-4

(Basis: source test requirements & monitoring)

46. 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: Regulation 2-2-306~~PSD Avoidance~~, SAM Periodic Monitoring)

47. 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. Recordkeeping: 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. Reporting: 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. Emission Offsets: The owner/operator shall provide ~~7.3 tons of valid POC emission reduction credits and~~ ~~27.945~~23.35 tons of valid NOx 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. District Operating Permit: 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. Deleted September 2010. ~~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 not operate S-5 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets). ~~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 S-5 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))~~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 operate S-5 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)~~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. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
    a. Hours of operation for reliability-related activities (maintenance and testing).
    b. Hours of operation for emission testing to show compliance with emission limits.
    c. Hours of operation (emergency).
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage for each engine(s). (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)~~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 ~~4~~8~~5~~5) 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~~Regulation 2-5)

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 43using 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~~ Regulation 2-5)

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 4~~3~~4. If three consecutive biennial source tests demonstrate that the annual emission rates for any of the compounds listed above calculated pursuant to part 4~~3~~5 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~~ Regulation 2-5)

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~~6,000 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: cumulative increase; Regulation 2-1-319)

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: cumulative increase; Regulation 2-1-319)

## VI. Conclusion

The District has reviewed the Authority to Construct for the LECEF Phase II conversion project (Authority to Construct 8859) and has concluded that, with the revisions discussed herein, the Authority to Construct satisfies the requirements for a two-year extension pursuant to District Regulation 2-1-407.1.2, including meeting current District BACT and offset requirements under District Regulations 2-2-301, 2-2-302, and 2-2-303. Upon revision of the facility's California Energy Commission License to conform to the revised conditions discussed herein, the District will grant the applicant's Request for Renewal of this Authority to Construct.

# Appendix A: Emissions Calculations

Emissions from the plant are calculated based on the BACT determinations made in Section III above.

**<u>Emission Factors</u>**

**Emission Factors for Nitrogen Oxides ($NO_x$ as $NO_2$)**

The $NO_x$ 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 $NO_x$, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(46.01 lb $NO_2$/lbmol)(8710 dscf/MMBTU)

= 0.00732 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) = **3.66 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) = **4.68 lb $NO_2$/hr**

**Emission Factors for Carbon Monoxide (CO)**

The CO emission factor used to calculate annual CO emissions from each turbine is based upon a maximum CO emission concentration of 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 CO, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(28 lb CO/lbmol)(8710 dscf/MMBTU)

= 0.00446 lb CO/MMBTU

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

(0.00446 lb CO/MM BTU)(500 MM BTU/hr) = **2.23 lb CO/hr**

The hourly 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) = **2.85 lb CO/hr**

**Emission Factors for Precursor Organic Compounds (POC)**

The POC emissions (as methane) from the turbine will be limited by permit condition to 1.0 ppmv, dry @ 15% $O_2$. This concentration is converted to a mass emission factor as follows:

(1.0 ppmvd)(20.95-0)/(20.95 – 15) = 3.52 ppmv, dry @ 0% $O_2$

($3.52/10^6$)(1 lbmol/385.3 dscf)(16 lb $CH_4$/lbmol)(8710 dscf/MMBTU)

= 0.00127 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:

(0.00126 lb POC/MM BTU)(500 MM BTU/hr) = **0.64 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) = **0.81 lb POC/hr**

**Emission Factors for 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 0.25 grains per 100 scf and a higher heating value of 1020 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(0.25 gr/100 scf)($10^6$ BTU/MM BTU)(2 lb $SO_2$/lb S)(lb/7000 gr)(scf/1020 BTU)

= 0.00070 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:

(0.00070 lb $SO_2$/MM BTU)(500 MM BTU/hr) = **0.35 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:

(0.00070 lb $SO_2$/MM BTU)(639 MM BTU/hr) = **0.45 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 1050 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/1020 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) = **1.36 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) = **1.74 lb $SO_2$/hr**

### Emission Factor for $PM_{10}$

A $PM_{10}$ emission factor of 2.5 lb/hr was used to calculate emissions for the simple-cycle plant and for the initial analysis of the combined-cycle conversion project. Based on further analysis of source test results for similar aeroderivitive turbines, the District expects that emissions will most likely be below 2.2 lb/hour at all times. There is still some debate among equipment manufacturers and operators regarding whether this lower rate can be guaranteed at all times, but at the very least it is an appropriate number on which to base longer-term emissions estimates such as annual $PM_{10}$ emissions rates.

### Emission Factor for Ammonia ($NH_3$)

The ammonia ($NH_3$) mass emission rate from the turbines will be limited by permit condition to 5 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:

(5.0 ppmvd)(20.95-0)/(20.95 – 15) = 17.61 ppmv $NO_x$, dry @ 0% O2

($17.61/10^6$)(1 lbmol/385.3 dscf)(17 lb $NH_3$/lbmol)(8710 dscf/MMBTU)

= 0.0068 lb $NH_3$/MMBtu

(0.0068 lb $NH_3$/MMBtu)(639 MMBtu/hr) = **4.34 lb/hr w/ duct firing**

(0.0068 lb $NH_3$/MMBtu)(500 MMBtu/hr) = **3.40 lb/hr w/ duct firing**

## <u>Maximum Emissions Summary</u>

**Maximum Hourly Emissions for Gas Turbines and HRSGs**

**Table A.1: Maximum Hourly Emission for Combined-Cycle Configuration**

- **(lb/hour-turbine-HRSG)**

| | **$NO_x$** | **POC** | **$PM_{10}$** | **CO** | **$SO_2$** |
|---|---|---|---|---|---|
| Emissions Rate | 4.68 | 0.81 | 2.2 | 2.85 | 1.79 |

The emissions listed are the maximum hourly emissions, excluding startup and shutdown.

### 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 two starts, followed by 20 hours of full load gas turbine operation with duct burner (DB) 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.

$NO_2$ = (2)(41 lb/event) + (40 lb/event) + (4.68 lb/hr)(20 hr full load w/DB firing)
= 175.6 lb/day/turbine/HRSG

CO = (2)(20 lb/event) + (2.85 lb/hr)(20 hr full load w/DB firing)

= 97.0 lb/day/turbine/HRSG

POC = (2)(2 lb/event) + (0.81 lb/hr)(20 hr full load w/DB firing)

= 20.2 lb/day/turbine/HRSG

$PM_{10}$ = (2.2 lb/hr)(24 hr full load w/DB firing)

= 52.8 lb/day/turbine/HRSG

$SO_2$= (1.79 lb/hr)(24 hr full load w/DB firing)

= 42.9 lb/day/turbine/HRSG

**Table A.2: Maximum Daily Emission for Combined-Cycle Configuration**

- **(lb/day-turbine-HRSG)**

| | **$NO_2$** | **POC** | **$PM_{10}$** | **CO** | **$SO_2$** |
|---|---|---|---|---|---|
| 2 Starts and Full Load with Duct Burner Firing | 175.6 | 20.2 | 52.8 | 97.0 | 42.9 |

- **Maximum 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:

- 6460 hours of full load operation per turbine per year @ 29°F without HRSG duct burner firing
- 1500 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29°F
- 400 start-up operations per year per gas turbine

This represents an anticipated operating scenario for the facility. The actual operation of the facility will be determined and dictated by both Pacific Gas and Electric (PG&E) pursuant to the terms of a power purchase agreement (PPA) and by the California Independent System Operator (ISO) based on grid conditions and demand. Because LECEF is equipped with four combustion turbines, it will have the advantage that, as grid conditions dictate and electricity demand changes throughout the day, individual combustion turbine/HRSG units can be shut-down completely, as opposed to operating a larger unit, such as an F-class gas turbine, at reduced load.

The above anticipated operating scenario is based upon the expectation that, upon conversion from simple-cycle to combined-cycle operations, LECEF will be dispatched as an intermediate to baseload facility. According to public testimony filed by PG&E with the California Public Utilities Commission (CPUC) requesting approval of its PPA with LECEF, upon conversion, LECEF will be subject to and meet the emissions performance standard required by Senate Bill (SB) 1368, which precludes utilities from signing long-term contracts for facilities with high GHG emissions.[58] Under the emissions performance standard adopted by the CPUC pursuant to SB 1368, generating facilities intended to provide electricity at an annualized capacity factor of 60 percent or greater (*i.e.*, "baseload", according to SB 1368) must achieve the emissions standard of 1,100 pounds of greenhouse gases (measured as carbon dioxide-equivalents)($CO_2$e) per megawatt-hour (MWh).[59] In its public testimony, PG&E describes the upgraded LECEF as "a dispatchable and operationally flexible resource" that will meet SB 1368's emissions performance standard[60] and support "PG&E's efforts to integrate renewal generation and enable overall reductions in GHG emissions in PG&E's portfolio."[61] Thus, information submitted by PG&E to the CPUC and by the applicant to the Air District indicates that LECEF 2 will be used to provide "shaping power", which will enable integration of renewable resources and, as a consequence of its location at a critical position within the grid, alleviate existing grid congestion.

In light of the foregoing anticipated operating scenario, the combined $NO_x$ (as $NO_2$) and CO emissions from the turbines and HRSGs will be limited by permit condition to 94.1tons/year and 53.4 tons/year, respectively. The accumulated mass emission totals for $NO_x$ 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

[58] Sen. Bill No. 1368, Stats. 2006 (2005-2006 Reg. Sess), ch. 598 § 8341(b)(4).

[59] CPUC, Adopted Interim Rules for Greenhouse Gas Emissions Performance Standards, R. 06-04-009, D.07-01-039 (Jan. 25, 2007).

[60] *See* Application of Pacific Gas and Electric Company for Approval of the Novation of the California Department of Water Resources Agreements Related to the Calpine Transaction, and Associated Cost Recovery, Prepared Testimony, Public Version, Oct. 30, 2009, Ch. 3, 3-9, 3-10.

[61] *Id*., at 3-10.

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.

$NO_x$ (as $NO_2$):

[(3.66 lb/hr)(6460 hr/yr) + (4.68 lb/hr)(1500 hr/yr) + (41 lb/startup)(400 startup/yr)](4 turbines)

= 188,254 lb $NO_2$/yr

= 94.1 ton/yr

POC:

[(0.64 lb/hr)(6460 hr/yr) + (0.81 lb/hr)(1500 hr/yr) + (2 lb/startup)(400 startup/yr)](4 turbines)

= 24,598 lb/yr

= 12.3 ton/yr

$PM_{10}$:

[(2.2 lb/hr)(6460 hr/yr) + (2.2 lb/hr)(1500 hr/yr) + (4.4 lb/startup)(400 startup/yr)](4 turbines)

= 77,088 lb/yr

= 38.5 ton/yr

CO:

[(2.23 lb/hr)(6460 hr/yr) + (2.85 lb/hr)(1500 hr/yr) + (20 lb/startup)(400 startup/yr) +

= 106,723 lb/yr

= 53.4 ton/yr

$SO_2$:

[(0.35 lb/hr)(6460 hr/yr) + (0.45 lb/hr)(1500 hr/yr) + (0.7 lb/startup)(400 startup/yr)](4 turbines)

= 12,864 lb/yr

= 6.43 ton/yr

$NH_3$:

[(3.4 lb/hr)(6460 hr/yr) + (4.34 lb/hr)(1500 hr/yr)](4 turbines)

= 113,896 lb/yr

= 56.94 ton/yr

| **Table A.3: Maximum Annual Emission for Combined-Cycle Configuration** <br> • **(ton/year for 4 turbine and HRSG trains)** | | | | |
|---|---|---|---|---|
| **$NO_2$** | **POC** | **$PM_{10}$** | **CO** | **$SO_2$** |
| 94.1 | 12.3 | 38.5 | 53.4 | 6.43 |

- **Maximum Annual Emissions for Fire Pump Diesel Engine**

| **Table A.4: 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] | 4.43 | 0.04 | 0.046 | 0.165 | 0.093 |
| ton/yr[b] | 1.11 | 0.01 | 0.01 | 0.04 | 0.02 |

- [a] Engine operation for discretionary purposes was limited to 45 minutes per day in the ATC that was issued in 2007. There is no basis for this limitation and it is therefore removed. A District Health Risk Analysis (See May 11, 2004 memorandum from Jane Lundquist to Dennis Jang) indicated that the levels of risk associated with the LECEF2 are acceptable for TBACT. The risk contribution from the firepump engine was based on 100 hours of annual operation allowed in the 2007 ATC for discretionary operation. This annual limitation is being reduced to 50 hours to comply with the current Stationery Diesel Engine ATCM (See Condition 19610, Part 39).
- [b] Based on 500 hr/yr of operation on fuel with a maximum sulfur content of 0.05% and engine rating of 300 bhp based on EPA Guidance. *See* Memorandum, from John S. Seitz (Director, Office of Air Quality Planning and Standards, U.S. EPA), to U.S. EPA Regional Air Division Directors, Subject: "Calculating Potential to Emit (PTE) for Emergency Generators", September 6, 1995, at p. 3. ("The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions."). Calculation for annual emissions is based on non-discretionary hourly emissions multiplied by 500 hours per year.

**Maximum Annual Emissions for Cooling Towers**

Emissions for One Cell Cooling Tower

The LECEF is currently 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: 6,000 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

$PM_{10}$ = (6,000 ppm)(35.4 lb/hr)/($10^6$)
= 0.212 lb/hr
= 5.10 lb/day (24 hr/day operation)
= 1860 lb/yr (8,760 operating hours per year)
= 0.93 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.

Emissions for 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: 6,000 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

$PM_{10}$ = (6,000 ppm)(182.65 lb/hr)/($10^6$)
= 1.096 lb/hr
= 26.30 lb/day (24 hr/day operation)
= 9600 lb/yr (8,760 operating hours per year)
= 4.80 ton/yr

**Maximum Annual Plant Emissions**

Table A.5 summarizes the maximum facility criteria pollutant emissions from the new combined-cycle facility. The permit conditions will be amended for the lower annual emissions of POC and CO.

- **Table A.5**

**Maximum Annual Facility Emissions, Combined-Cycle Configuration (tons/yr)**

| | **$NO_x$** | **POC** | **$PM_{10}$** | **CO** | **$SO_2$** |
|---|---|---|---|---|---|
| Turbines and HRSGs | 94.1 | 12.3 | 38.5 | 53.4 | 6.43 |
| Fire Pump Diesel Engine | 1.11 | 0.01 | 0.01 | 0.04 | 0.02 |
| One-Cell Cooling Tower | 0 | 0 | 0.93 | 0 | 0 |
| Six-Cell Cooling Tower | 0 | 0 | 4.80 | 0 | 0 |
| **Total** | **95.21** | **12.31** | **44.24** | **53.44** | **6.45** |