Final
Determination of Compliance

Delta Energy Center

Bay Area Air Quality Management District
Application 19414

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I Introduction

This is the Final Determination of Compliance (FDOC) for the Delta Energy Center (DEC), a nominal 880-MW, natural-gas-fired, combined cycle merchant power plant proposed by Calpine Corporation and Bechtel Enterprises, Inc.. The power plant will be located on the Dow Chemical USA complex in the city of Pittsburg and will be composed of three nominal 200-MW combustion gas turbines, three heat recovery steam generators equipped with 200 MM BTU/hr duct burners, one 300-MW steam turbine generator, and two 256 MM BTU/hr natural-gas-fired auxiliary boilers. The DEC will also include an existing cogeneration facility consisting of three gas turbines and three waste heat boilers with a combined nominal output of 70 MW. These units are currently owned and operated by Calpine Pittsburg, Inc. and are identified under BAAQMD plant number 11928.

A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Final Determination of Compliance (FDOC) document for the Delta Energy Center. It will also serve as the evaluation report for the District Authority to Construct application #19414 and serves as the final PSD permit under delegated authority from the EPA. The FDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included.

Pursuant to Regulation 2, Rule 3, Section 404, this FDOC is subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407. A public notice describing the location, capacity, and air pollutant emissions from the project was published in the Contra Costa Times on August 24, 1999. The 30-day public comment period officially ended on September 24, 1999. Public comments on the PDOC were received, considered, and responded to in writing. The applicant has proposed changes to some of the permit conditions in response to comments from the ARB and EPA.

Because the current Calpine facility emissions exceed 100 tons per year each for CO and PM_{10}, it is considered a Major Facility with regard to Major Facility Review and PSD for those pollutants pursuant to Regulations 2-2-220.1 and 2-2-220.3. Because the addition of the three new turbines and three new HRSGs will result in increases in facility NO_x, CO, POC, and PM_{10} emissions in excess of 40 tons per year, this project is considered to be a major modification of a Major Facility.

B. Project Description

1. Process Equipment

The applicant is proposing a combined-cycle cogeneration facility capable of producing a nominal electrical output of 880 MW. The Delta Energy Center will consist of the following new permitted equipment:

S-1 Combustion Gas Turbine #1, General Electric 7251FA or Westinghouse 501FD; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-1 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, General Electric 7251FA or Westinghouse 501FD equivalent; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-2 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-2 Selective Catalytic Reduction System

S-5 Combustion Gas Turbine #3, General Electric 7251FA or Westinghouse 501FD; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-3 Selective Catalytic Reduction System

S-6 Heat Recovery Steam Generator #3, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-3 Selective Catalytic Reduction System

S-7 Auxiliary Boiler #1, equipped with low-NO_x burners, 256 MM BTU per hour, abated by A-4 Oxidation Catalyst and A-5 Selective Catalytic Reduction System

S-8 Auxiliary Boiler #2, equipped with low-NO_x burners, 256 MM BTU per hour, abated by A-6 Oxidation Catalyst and A-7 Selective Catalytic Reduction System

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by all three heat recovery steam generators (HRSGs) will feed to a single nominal 300-MW steam turbine generator.

The Delta Energy Center will also include the following new pieces of equipment that do not require District operating permits:

- 14-Cell Wet Cooling Tower; 12,318,000 gallons per hour

  The cooling tower is exempt from District permit requirements pursuant to Regulation 2-1-128.4 since it will not be used for the evaporative cooling of process water. Because the projected PM_{10} emissions from the cooling tower (14.1 tons/yr) approach the PSD significance level of 15 tons/yr as specified in 40 CFR 52.21(23)(i), the District has agreed to include permit conditions requiring monitoring and maintenance for the cooling towers to insure on-going compliance with the PSD BACT requirements in response to written comments from EPA Region IX. As exempt sources, the cooling towers will not be subject to District New Source Review requirements and therefore not be subject to the PM_{10} emission offset requirement.

- Fire Pump Diesel Engine, Cummins Model 6CTA8.3-F3; 300 hp

  The diesel engine is exempt from District permit requirements pursuant to Regulation 2-1-113.2.10, since it will be used solely for the emergency pumping of water.

- Emergency Generator, Caterpillar Model G3612-TA, Natural Gas Fired, 21.02 MM BTU/hr

  District Regulations, including permit requirements, do not apply to “any internal combustion engine used solely as an emergency standby source of power” pursuant to District Regulation 1-110.2.

The Delta Energy Center will also include the following existing permitted equipment currently owned and operated by Calpine Pittsburg Inc. under District plant #11928:

S-67 Gas Turbine T-1, Pratt and Whitney FT4A-9GF, 262 MM BTU/hr, 19.4 MW, abated by A-188 Selective Catalytic Reduction Unit

S-68 Waste Heat Boiler #1, 155.5 MM BTU/hr, abated by A-188 Selective Catalytic Reduction Unit

S-70 Gas Turbine T-2, Pratt and Whitney FT4C-1DGF, 292 MM BTU/hr, 20 MW, abated by A-189 Selective Catalytic Reduction Unit

S-71 Waste Heat Boiler #2, 155.5 MM BTU/hr, abated by A-189 Selective Catalytic Reduction Unit

S-73 Gas Turbine T-3, Pratt and Whitney FT4C-1DGF, 330 MM BTU/hr, 25.4 MW, abated by A-190 Selective Catalytic Reduction Unit

S-74 Waste Heat Boiler #3, 155.5 MM BTU/hr, abated by A-190 Selective Catalytic Reduction Unit

2. Equipment Operating Scenarios

New Turbines and Heat Recovery Steam Generators

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

Base Load: Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

HRSG Duct Burner Firing with Steam Injection Power Augmentation:

Under peak demand situations and high ambient temperatures, steam is injected into the CTG combustors to lower the flame temperature and allow increased fuel flow resulting in increased mass through the gas turbine thereby increasing electrical output

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 6,844 hours of baseload (100% load) operation per year for each CTG @ 30^{o}F
- 1,500 hours of duct burner firing per HRSG per year with steam injection power augmentation at CTG combustors
- 156 one-hour hot start-ups per CTG per year
- 52 three-hour cold start-ups per CTG per year

New Auxiliary Boilers

Each of the auxiliary boilers will be capable of providing up to 200,000 lb/hr of 200 psig saturated steam to the Dow Chemical Company facility when the turbines and HRSGs are not in operation. At least one boiler will operate at maximum turndown (10% load) at all times to minimize any interruption in steam flow to Dow that may result from upsets to the gas turbine/HRSG power trains.

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the auxiliary boilers.

Auxiliary Boiler #1: 540 hr/yr @ 100% load, 8,220 hr/yr @ 10% load
Auxiliary Boiler #2: 40 hr/yr @ 100% load, 8,720 hr/yr @ 10% load

Existing Turbines and Waste Heat Boilers

The existing turbines and waste heat boilers are currently operated as baseload units that supply electricity and approximately 200,000 lb/hr of 200 psig process steam to the Dow Chemical Company. When the new turbines and HRSGs become operational, one of the existing turbines will be operated as a peaking unit (i.e. will provide backup and supplemental power during period of peak demand) and the remaining two pairs of turbines and waste heat boilers will be operated on a limited basis to provide supplemental power and process steam to the Dow Chemical Company.

3. Air Pollution Control Strategies and Equipment

The proposed facility includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NO_x), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The gas turbines, HRSG duct burners, and auxiliary boilers each trigger BACT for NO_x emissions. The gas turbines and HRSGs will be equipped with dry low-NO_x (DLN) combustors, which are designed to minimize NO_x emissions. In addition, the NO_x emissions will be further reduced through the use of abatement equipment in the form of selective catalytic reduction (SCR) systems with ammonia injection. The auxiliary boilers will also be equipped with low-NO_x burners to minimize NO_x emissions and each will be abated by selective catalytic reduction (SCR) systems with ammonia injection.

b. Good Combustion Practices and Oxidation Catalyst for the Control of CO Emissions

The gas turbines, HRSG duct burners, and auxiliary boilers each trigger BACT for CO emissions. The combustion turbines and HRSGs will be equipped with dry low-NO_x combustors, which are also designed to minimize CO emissions. The HRSGs will be designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations. The CO emissions from each auxiliary boiler will be minimized through the use of good combustion practices and further reduced through the use of oxidation catalysts.

c. Dry Low-NO_x (DLN) Combustors and Oxidation Catalysts to Minimize POC Emissions

The Gas Turbines, HRSGs and Auxiliary Boilers each trigger BACT for POC emissions. Each of these sources will utilize dry low-NO_x combustors, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the auxiliary boilers will be abated by oxidation catalysts that will insure that the boilers will maintain a BACT-level CO emission concentration of 50 ppmvd @ 3% O_2.

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

The gas turbines, HRSG duct burners, and auxiliary boilers will utilize natural gas exclusively 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.

II Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

Table 1 is a summary of the daily maximum regulated air pollutant emissions for each new permitted source, including the gas turbines, heat recovery steam generators (HRSGs), and the auxiliary boilers. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of Regulation 2, Rule 2 New Source Review (NSR) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, NO_x, SO_2, PM_{10}, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement.

Table 1
Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources (lb/day)

Pollutant	Source				
	S-1 CTG #1 & S-2 HRSG #1[a]	S-3 CTG #2 & S-4 HRSG #2[a]	S-5 CTG #3& S-6 HRSG #3[a]	S-7 Aux. Boiler[b]	S-8 Aux. Boiler[b]
Nitrogen Oxides (as NO_2)	699.8	699.8	699.8	66.4	66.4
Carbon Monoxide	4,340.26	4,340.26	4,340.26	224.3	224.3
Precursor Organic Compounds	169.44	169.44	169.44	12.9	12.9
Particulate Matter (PM_{10})	280.2	280.2	280.2	48	48
Sulfur Dioxide	35	35	35	4.3	4.3

[a]Based upon one 3-hour cold start-up, one 1-hour hot startup, 16 hours of CTG/HRSG baseload operation at maximum combined firing rate of 2,125 MM BTU/hr with steam injection power augmentation at the CTG combustors and four hours of 100% load CTG operation at 2,003 MM BTU/hr in one day

[b]Based upon 24 hour per day operation of each auxiliary boiler at its maximum firing rate of 256 MM BTU/hr

Table 2 is a summary of the maximum annual regulated air pollutant emissions from the Delta Energy Center and includes emissions from new and existing sources.

Table 2
Maximum Annual Facility Regulated Air Pollutant Emissions for Permitted Sources

Pollutant	Annual Emissions[a] (ton/yr)
Nitrogen Oxides (as NO_2)	298.17
Carbon Monoxide	1,229.36
Precursor Organic Compounds	79.37
Particulate Matter (PM_{10})[b]	161.77[b]
Sulfur Dioxide	19.22

[a]includes emissions from existing turbines and waste heat boilers based upon proposed reduced annual operating rates

[b]includes PM_{10} emissions from exempt cooling towers

Table 3 is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the A-1, A-2, A-3, A-5, and A-7 SCR Systems.

Table 3
Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	pounds/year	Risk Screening Trigger Level[a] (lb/yr)
S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8 Combined[b]		
Acetaldehyde[d]	3,559	72
Acrolein	1,227	3.9
Ammonia[c]	714,669	19,300
Benzene[d]	709	6.7
1,3-Butadiene[d]	6.6	1.1
Ethylbenzene	928.3	193,000
Formaldehyde[d]	5,945	33
Hexane	13,403	83,000
Naphthalene	86.2	270
PAHs[d]	120.5	0.043
Propylene	40,024	N/S
Propylene Oxide[d]	2,475	52
Toluene	3,684	38,600
Xylene	1,356.6	57,900
Exempt Cooling Tower Emissions		
Aluminum	15,592	N/S[e]
Arsenic[d]	**1.33**	0.024
Cadmium[d]	**1.58**	0.046
Trivalent chromium[d]	2.4	0.0014
Copper	4.67	463
Lead[d]	2.92	29
Mercury	1.24	57.9
Nickel	0.007	96.5
Silver	2.04	N/S
Zinc	0.05	6,760

[a]pursuant to District Toxic Risk Management Policy

[b]combined TAC emissions from the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8)

[c]based upon the worst-case ammonia slip of 10 ppmvd @ 15% O_2 from the A-1, A-2, A-3, A-5, and A-7 SCR systems with ammonia injection

[d]carcinogenic compound

[e]none specified

Table 4 is a summary of the cumulative increase in regulated air pollutant emissions for the facility from existing and proposed permitted sources. The cumulative increase in emissions since the PSD Baseline Date in tons per year are used to determine if the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304 and 2-2-305) have been triggered for each pollutant.

Table 4
Facility Cumulative Regulated Air Pollutant Emissions Increase[a]

Pollutant	Cumulative Increase[b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	206.37	40
Carbon Monoxide	903.76	100
Precursor Organic Compounds	65.75	N/A[d]
Particulate Matter (PM_{10})	127.375	15
Sulfur Dioxide	15	40

[a]reflects net emission increases from proposed turbines, HRSGs, and auxiliary boilers after contemporaneous emission reductions from existing turbines and waste heat boilers

[b]Includes start-up emissions for gas turbines (52 total cold start-ups and 156 total hot start-ups per year per turbine)

[c]applies to a major modification of a major facility

[d]there is no PSD requirement for POC since it is not a criteria pollutant

III Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed project will comply with those requirements.

A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed DEC facility are Section 2-2-301; “Best Available Control Technology Requirement”, Section 2-2-302; “Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR”, and Section 2-2-303; “Offset Requirement, PM_{10} and Sulfur Dioxide, NSR” and Section 2-2-404, “PSD Air Quality Analysis”.

1. 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 EPA. 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. 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 Delta Energy Center. Because each Gas Turbine and its associated HRSG 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.

Nitrogen Oxides (NO_x)

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT (achieved in practice) for NO_x for a gas turbine with a rated heat input $\geq$ 23 MM BTU per hour as NO_x emissions < 5 ppmvd @ 15% O_2, achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with combustion modifications. The SCAQMD BACT Guideline for gas turbines $\geq$ 3 MW specifies BACT for NO_x as 2.5 ppmvd, @ 15% O_2 with an efficiency correction factor and an assumed averaging period of one hour. This BACT determination was based upon the demonstration of a SCONOX system on a 32 MW combined cycle, baseload turbine currently in operation in Vernon, California. The EPA has accepted this BACT determination as Federal LAER and further established a NO_x concentration of 2.0 ppmvd @ 15% O_2 averaged over three hours as equivalent to 2.5 ppmvd, @ 15% O_2 averaged over one hour.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.5 ppmvd NO_x @ 15% O_2 averaged over one hour at all times except during turbine start-ups and shutdowns. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with dry low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner emissions will also be abated by the SCR system with ammonia injection mentioned above and when combined with the CTG exhaust, will achieve NO_x emission concentrations of 2.5 ppmvd @ 15% O_2, averaged over one hour.

- Auxiliary Boilers

  District BACT Guideline 17.3.1 specifies BACT (achieved in practice) for NO_x for a boiler with a rated heat input $\geq$ 50 MM BTU/hr as a NO_x emission concentration of 9 ppmvd @ 3% O_2. The proposed auxiliary boilers (S-7 and S-8) are expected to achieve this NO_x emission level through the use of dry low-NO_x combustors and abatement by Selective Catalytic Reduction Systems with ammonia injection.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine alone over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection lowers the combustor flame temperature thereby allowing an increased fuel use rate, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature.

- Combustion Gas Turbines

District BACT Guideline 89.2.1 specifies BACT (achieved in practice) for CO for gas turbines with a rated heat input $\geq$ 23 MM BTU per hour as a CO emission concentration of 10 ppmvd @ 15% O_2. BACT (technologically feasible/cost-effective) is specified as a CO emission concentration of < 6 ppmvd @ 15% O_2. Both BACT specifications do not specify turbine/HRSG operating mode.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O_2, it established the technologically feasible/cost-effective BACT specification cited above. However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% O_2 under all loads and ambient conditions with and without duct burner firing. Crockett has not employed steam injection power augmentation during peak load/high ambient temperature situations since the resulting CO emission concentration would exceed the current emission limit of 5.9 ppmvd CO. Based upon their operating experience, they do not expect to consistently meet 10 ppmvd CO when operating in steam injection power augmentation mode. Therefore, the achieved-in-practice BACT for CO does not apply to the steam injection power augmentation mode.

The Pittsburg District Energy Facility (PDEF) was recently issued a permit with a CO emission concentration limit of 6 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because the PDEF proposed this limit, it was accepted as meeting BACT for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated in actual operation.

Therefore, achieved in practice BACT for CO is deemed to be 10 ppmvd CO @ 15% O_2 for the combined exhaust from the gas turbine/HRSG duct burners during all modes of operation except gas turbine start-up, shutdown, and steam injection power augmentation mode. During steam injection power augmentation, BACT for CO for the CTG/HRSG power train is deemed to be a combined CO emission limit of 24.3 ppmvd @ 15% O_2, averaged over any consecutive three hour period, as proposed by DEC.

In response to written comments from the ARB and EPA, the applicant has agreed to a CO emission limit of 10 ppmvd @ 15% O_2, averaged over any consecutive three hour period, that will apply to the firing of the turbine alone, turbine operation with duct burner firing, and steam injection power augmentation mode. The applicant intends to achieve compliance with this BACT specification through the use of dry low-NO_x combustors which minimize incomplete combustion. DEC expects to meet these emission limitations without the use of an oxidation catalyst. If the DEC cannot consistently meet these emission limitations, permit condition 30 requires that the HRSG and associated ductwork be designed such that it can readily accept an oxidation catalyst, which must be installed at the discretion of the BAAQMD.

- Heat Recovery Steam Generators (HRSGs)

Because the HRSG duct burners are not fired unless the gas turbine is in operation, BACT applies to the combined exhaust from each gas turbine/HRSG power train. As stated earlier, BACT (Achieved in Practice) for the combined exhaust from the gas turbine and HRSG is a CO emission level of 10 ppmvd @ 15% O_2, averaged over any consecutive three hour period. As stated above, this BACT specification applies during duct burner firing and steam injection power augmentation mode, but does not apply during gas turbine start-up, shutdown,.

The HRSG will be equipped with dry low-NO_x burners, which will minimize incomplete combustion and thereby minimize CO emissions. However, when the HRSG duct burners are firing and steam injection power augmentation is occurring at the gas turbine combustors, the combined exhaust from the turbine/HRSG will be as high as 24.3 ppmvd CO @ 15% O_2. As stated earlier, DEC expects to meet these emission limitations without the use of an oxidation catalyst.

- Auxiliary Boilers

With highest-day CO emissions of 224.3 pounds, S-7 and S-8 Auxiliary Boilers each trigger the BACT requirement of New Source Review (District Regulation 2, Rule 2) for Carbon Monoxide. BAAQMD BACT Guideline 17.3.1 specifies BACT for CO for boilers with a rated heat input $\geq$ 50 MM BTU/hr as a CO emission concentration of 50 ppmvd @ 3% O_2. The proposed auxiliary boilers will be limited by permit condition to a CO emission concentration of 50 ppmvd @ 3% O_2, averaged over any consecutive three hour period. Each auxiliary boiler will achieve this CO emission level through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

District BACT Guideline 89.2.1 specifies BACT for POC for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as 50% reduction by weight which is typically achieved through the use of an oxidation catalyst. Because the sampling of the turbine exhaust upstream of the oxidation catalyst is problematic due to exhaust gas flow rate measurement inaccuracy caused by the proximity of the HRSG, the verification of the reduction efficiency is not feasible. 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 mass emission rate limitation to be verified by annual source testing.

The applicant has proposed a POC mass emission rate of 8 lb/hour without the use of an oxidation catalyst based upon turbine vendor guarantees. This converts to an emission factor of 0.004 lb/MM BTU and an emission concentration of 3.2 ppmvd @ 15% O_2. Based upon their analysis of gas turbine source test data, the applicant has argued that an oxidation catalyst will not achieve significant reductions in POC emissions and that the catalyst will increase PM_{10} emissions by converting SO_2 to SO_3 which would lead to a corresponding increase in the formation of particulate sulfates.

In response to comments from EPA and ARB, the applicant has accepted a BACT specification of 2 ppmvd POC @ 15% O_2 that will apply during all operating modes except start-up and shutdown. This converts to an emission factor of 0.00251 lb/MM BTU and a mass emission rate of 5.03 lb/hr.

- Heat Recovery Steam Generators (HRSGs)

The HRSG duct burners will be of low-NO_x design and therefore minimize incomplete combustion, resulting in a reduced POC emission rate of 0.02 lb/MM BTU and 4 lb/hr. As in the case of the gas turbine discussed above, BACT for POC is deemed to be a mass emission rate limitation to be verified by annual source testing.

The applicant has proposed a combined POC mass emission rate of 12 lb/hour for simultaneous firing of the turbine and HRSG duct burners, without the use of an oxidation catalyst, based upon turbine and HRSG vendor guarantees. This converts to an emission factor of 0.00565 lb/MM BTU and emission concentration of 4.5 ppmvd @ 15% O_2.

In response to comments from EPA and ARB, the applicant has accepted a BACT specification of 2 ppmvd POC @ 15% O_2 that will apply during all operating modes, including duct burner firing, but excluding turbine start-up and shutdown. This converts to an emission factor of 0.00251 lb/MM BTU and a combined mass emission rate of 5.33 lb/hr.

- Auxiliary Boilers

With worst-case daily POC emissions in excess of 10 pounds, the auxiliary boilers trigger the BACT requirement of New Source Review (District Regulation 2-2-301) for POC. Current BACT Guideline 17.3.1, which applies to boilers with a heat input of $\geq$ 50 MM BTU/hr, specifies BACT for POC as good combustion practices. As stated earlier, the auxiliary boilers will utilize low-NO_x burners that are also designed to minimize incomplete combustion and therefore minimize POC emissions.

Each auxiliary boiler will also be abated by an oxidation catalyst. However, in keeping with their previous contention regarding the effectiveness of oxidation catalyst for POC conversion, the applicant has assumed no POC reduction for the oxidation catalyst. The design specifications for the auxiliary boilers specify a maximum POC emission rate of 0.53 lb/hr at full load. This is equivalent to an emission factor of 0.0021 lb/MM BTU and an emission concentration of 5 ppmvd @ 3% O_2.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

District BACT Guideline 89.2.1 specifies BACT for SO_2 for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, which will result in minimal SO_2 emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 0.25 gr/100 scf of natural gas. This corresponds to an SO_2 emission factor of 0.0007 lb/MM BTU. The natural gas sulfur content specification of 0.25 gr/100 scf is deemed BACT for SO_2.

- Heat Recovery Steam Generators (HRSGs)

As is the case of the Gas Turbines, BACT for SO_2 for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 0.25 gr/100 scf of natural gas.

- Auxiliary Boilers

As is the case for the Gas Turbines and HRSGs, BACT for SO_2 for the auxiliary boilers is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 0.25 gr/100 scf of natural gas.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

District BACT Guideline 89.2.1 specifies BACT for PM_{10} for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, which will result in minimal nitrate and sulfate particulate formation. Furthermore, the limiting of the sulfur content of the natural gas to 0.25 gr/100 scf of natural gas will insure that the sulfate particulate formation is minimized.

- Heat Recovery Steam Generators (HRSGs)

As is the case of the Gas Turbines, BACT for PM_{10} for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 0.25 gr/100 scf of natural gas.

- Auxiliary Boilers

  As is the case for the Gas Turbines and HRSGs, BACT for PM_{10} for the auxiliary boilers is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 0.25 gr/100 scf of natural gas.

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally-enforceable emission reduction credits are required for POC and NO_x emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. Because the DEC facility will emit 50 tons per year or more on a pollutant-specific basis, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.1 and 302.2, NO_x offsets may be used to offset emission increases of POC and POC offsets may be used to offset emission increases of NO_x.

Pursuant to Regulation 2-2-303, emission offsets shall be provided (at a ratio of 1:1) for PM_{10} emission increases at new facilities that will be permitted to emit more than 100 tons of PM_{10} per year. Pursuant to Regulation 2-2-303.1, emission reduction credits of nitrogen oxides or sulfur dioxide may be used to offset PM_{10} emission increases.

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required only for permitted sources. Therefore, emission offsets will be required for the POC, NO_x, and PM_{10} emission increases associated with S-1, S-3, and S-5 Gas Turbines, S-2, S-4, and S-6 HRSGs, and S-7 and S-8 Auxiliary Boilers only. Emission offsets will not be required for the PM_{10} emissions attributed to the exempt cooling towers and the POC, NO_x, and PM_{10} emissions from the fire pump diesel engine and emergency generator. Please see Appendix C for further detail.
It should be noted that in the case of POC and NO_x offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

Timing for Provision of Offsets

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. Historically, the BAAQMD has not required the applicant to provide the actual banking certificates to the District prior to the issuance of the authority to construct. Rather, the District has accepted the applicant’s demonstration of control of valid offsets through enforceable contracts or options to purchase as equivalent to the "provision" of offsets as required by Regulation 2-2-311. The actual banking certificates must be surrendered to the District prior to the start of construction.

Interpollutant Trade-Off Ratios

Pursuant to District Regulation, 2-2-303.1, an applicant can provide NO_x and/or SO_2 emission reduction credits to offset PM_{10} emission increases at ratios deemed appropriate by the APCO. Pursuant to current District policy, the default interpollutant trade-off ratios for Eastern Contra Costa County are 6 to for NO_x to PM_{10} and 4 to 1 for SO_2 to PM_{10}. These ratios represent the "conservative best-estimate values" from an interpollutant trade-off ratio analysis conducted by Systems Applications International (SAI) for the Shell Refinery located in Martinez, California. More specifically, the analysis specifies a "best estimate" trade-off ratio for the Pittsburg area of 3 to 1 for SO_2 to PM_{10}. Because the Delta Energy Center will be located in Pittsburg, the trade-off ratio of 3 to 1 will apply to this project. Please see Appendix C, Attachment 2 for the District policy memorandum regarding this trade-off ratio.

The SAI analysis utilized three methods to estimate the amount of secondary PM_{10} formation resulting from the emission of NO_x and SO_2. The first method was based entirely upon an analysis of ambient air quality data. The second method used a photochemical box model to compute the aerosol yield from a unit of NO_x or SO_x emissions. The third method used the photochemical model to simulate the effect of an incremental unit of precursor emissions on typical atmosphere with variable mixing height. The interpollutant trade-off ratios generated by the SAI analysis only apply to facilities located in the Eastern portion of Contra Costa County. Under current policy, if an applicant wishes to utilize different (i.e. lower) interpollutant offset ratios, they must submit an analysis for review by the District Planning Division.

Offset Requirements by Pollutant

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the DEC will emit greater than 50 tons per year of Precursor Organic Compounds (POCs), the applicant must provide emission reduction credits (ERCs) of POC at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.1, the applicant has the option to provide NO_x ERCs in lieu of POC ERCs at a trade-off ratio of 1 to 1, to offset a portion of the proposed POC emission increases from the DEC.

NO_x Offsets

Because the DEC will emit greater than 50 tons per year of Nitrogen Oxides (NO_x), the applicant must provide emission reduction credits (ERCs) of NO_x at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.2, the applicant has the option to provide POC ERCs in lieu of NO_x ERCs at a trade-off ratio of 1 to 1 to offset the NO_x

emission increases from the DEC, provided that the PSD requirement of Regulation 2-2-304 are satisfied. The final offset package from the applicant indicates that they have opted to provide POC ERCs to offset a portion of the NO_x emissions increases for the DEC. See Appendix C, Attachment 1 for a discussion of the rationale for interpollutant trading of NO_x for POC.

PM_{10} Offsets

With projected PM_{10} emissions of greater than 100 tons per year, the DEC is considered to be a Major Facility for PM_{10} pursuant to District Regulation 2-2-220.1. Therefore, emission offsets must be provided at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-303. Pursuant to District Regulation, 2-2-303.1, the applicant has opted to provide SO_2 ERCs to offset a portion of the proposed PM_{10} emission increases at offset ratios deemed appropriate by the APCO. As stated earlier, the standard BAAQMD interpollutant trade-off ratios for the Pittsburg area is 3 to 1 for SO_2 to PM_{10}.

SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increases associated with this project since the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow 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.

Contemporaneous Emission Reduction Credits

Pursuant to District Regulations 2-2-214 and 2-2-242, the Delta Energy Center will provide contemporaneous emission reduction credits (ERCs) to offset a portion of the proposed NO_x, POC, and PM_{10} emission increases for the facility. These contemporaneous ERCs will result from the reduced operation of the existing permitted turbines (S-67, S-70, & S-73) and waste heat boilers (S-68, S-71, & S-73) currently in operation at the Calpine Pittsburg, Inc. facility.

The baseline NO_x emissions for the existing turbines and waste heat boilers were determined pursuant to District Regulation 2-2-605.2 (Emission Calculation Procedures, Emission Reduction Credits) and were based upon the actual annual emissions from the sources, averaged over the highest twelve consecutive month period occurring during the last five years immediately preceding this application. The NO_x baseline emissions have been adjusted to reflect the NO_x emission reduction requirements of Regulation 9, Rule 9, "Nitrogen Oxides from Stationary Gas Turbines".

The baseline POC and PM_{10} emissions for the existing turbines and waste heat boilers were also determined pursuant to District regulation 2-2-605.2 (Emission Calculation Procedures, Emission Reduction Credits) and were based upon the actual annual emissions from the sources, averaged over the highest twelve consecutive month period occurring during the last five years immediately preceding this application and the results of source testing conducted on July 21, 1999.

Table 5 summarizes the contemporaneous emission reduction credits resulting from the reduced operation of the existing turbines and waste heat boilers. The quantities will reduce the total offset obligation of the Delta Energy Center as shown in Appendix C, Table C-1.

Table 5
Contemporaneous Emission Reduction Credits Generated by Existing Gas Turbines

Pollutant	Annual Emissions (lb/yr)	Annual Emissions (ton/yr)	Proposed Annual Emission Limitations (ton/yr)	Contemporaneous Emission Reductions (ton/yr)
NO_x (as NO_2)	192,414	96.21	18.5	77.71
PM_{10}	40,850.9	20.425	7.1	13.325
POC (as CH_4)	27,233.9	13.62	4.7	8.92

Offset Package

Table 6 summarizes the current offset obligation of the Delta Energy Center and the quantity of valid emission reduction credits (ERCs) controlled by the Calpine Corporation. All ERCs presented in Table 6 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, “Emissions Banking”, and were subsequently issued as banking certificates by the BAAQMD.

As indicated, the applicant has sufficient valid emission reduction credits under their control to offset the emission increases from the permitted sources proposed for the Delta Energy Center. As currently proposed, the applicant has acquired sufficient surplus POC emission reduction credits (33.263 tons) to offset the outstanding balance of 33.19 tons of NO_x at the BAAQMD interpollutant trading ratio of 1 to 1 pursuant to Regulation 2-2-302.2. The District rationale for allowing this interpollutant trade-off is described in the memorandum dated October 13, 1999 which is attached to Appendix C. Furthermore, the applicant has identified sufficient SO_2 emission reduction credits to offset the outstanding balance of 38.44 tons of PM_{10} at the applicable BAAQMD interpollutant trade-off ratio of 3 to 1. The surplus SO_2 ERCs are calculated as follows:

133.62 tons SO_2 - (3)(38.44 tons PM_{10}) = +18.30 tons of SO_2

Table 6
Valid Emission Reduction Credits Controlled by DEC as of October 20, 1999

		BAAQMD	BAAQMD				

Company Name	Location	Banking Certificate Number	Application Number[a]	POC (ton/yr)	NO_x (ton/yr)	SO_x (ton/yr)	PM_{10} (ton/yr)
C&H Sugar	Crockett	610	16446	0	0	71.59	0
Courtaulds Aerospace, Inc.	Berkeley	403	14108	3.12	0	0	0
Courtaulds Aerospace, Inc.	Berkeley	511	16693	20.60	0	0	0
Crown Cork & Seal	Pittsburg	608	32763	2.783	0	0	0
Crown Cork & Seal	Richmond	271	10865	53.26	0	0	0
Dexter Hysol	Pittsburg	626	9539	19.20	0	0	0
Dupont	Antioch	618	27269	1.60	14.56	0	2.21
Homestake Mining	Napa	587	18058	0	22.07	1.30	21.72
P.G.&E.	Rodeo	100	1388	8.00	162.35	60.73	65.00
Total Valid Emission Reduction Credits Acquired				108.563	198.98	133.62	88.93
Offsets Required per BAAQMD Calculations				75.30	232.17	0	127.37
Outstanding Offsets				**+33.263**	**-33.19**	**+133.62**	**-38.44**

[a]original banking application; includes evaluation report that certifies that the emission reduction credits are real, quantifiable, permanent, and enforceable.

3. PSD Air Quality Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately demonstrates the air quality impacts of the DEC project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the DEC project, in conjunction with all other applicable emissions, will not cause or contribute to a violation of any applicable ambient air quality standard for NO_2, CO, and PM_{10} or an exceedance of any applicable PSD increment.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

Please see Appendix E for a detailed discussion of the air quality impact analysis.

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the DEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the DEC are summarized on page 8, Table 2. In accordance with the requirements of the BAAQMD Risk Management Policy and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

Table 7 Health Risk Assessment Results

Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index
0.16	0.04	0.06

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to comply with current accepted practice as well as BAAQMD policies and procedures. Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. Furthermore, the acute and chronic hazard indices attributed to this project are considered to be not significant since they are each less than 1.0. Therefore, the DEC facility is deemed to be in compliance with the BAAQMD Risk Management Policy. Please see Appendix D for further detail.

C. 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 Delta Energy Center has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1, S-3, & S-5 Combustion Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators, and S-7 & S-8 Auxiliary Boilers.

Because the proposed cooling towers will not be used for the evaporative cooling of process water, it is exempt from District permit requirements (Regulation 2-1-301 and 2-1-302) pursuant to Regulation 2, Rule 1, Section 128.4. Although worst-case emission projections indicate that the cooling towers will emit toxic air contaminants at rates in excess of their risk management screening trigger levels as specified in Table 2-1-316 of Regulation 2, Rule 1, the applicant has demonstrated that the cooling tower emissions pass a risk screening analysis in accordance with the District Air Toxic Risk Screening Procedure. Therefore, the cooling towers remain exempt from District permit requirements per Regulation 2-1-316.

The proposed 300 hp fire pump diesel engine is exempt from District permit requirements pursuant to Regulation 2-1-113.2.10, since it will be used exclusively for the emergency pumping of water.

The proposed natural gas fired emergency generator is not subject to any District regulations, including permit requirements, since it is an internal combustion engine used solely as an emergency standby source of power.

Regulation 2, Rule 2, Section 101:

Because the District New Source Review Regulation incorporates by reference the federal PSD regulations and the BAAQMD has received delegated authority from the U.S. EPA to administer the PSD permit program, the FDOC serves as the final PSD permit for the Delta Energy Center. Consequently, the 30-day public comment period for the PDOC also serves as the 30-day comment period for the PSD permit for the DEC.

The Final PSD Permit will become effective 30 days from the date of issuance of the FDOC unless a timely appeal is filed with the Environmental Appeals Board pursuant to 40 CFR 124.19.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Final Determination of Compliance (FDOC) serves as the APCO's final decision as to whether the proposed power plant will meet the requirements of applicable District regulations. The FDOC contains proposed permit conditions to ensure compliance with District regulations. Pursuant to Regulation 2-3-304, the FDOC will be subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. On February 1, 1999, the District determined pursuant to Regulation 2-2-402 that the Application for Certification contained sufficient information for the District to undertake a Determination of Compliance review.

Regulation 2, Rule 6: Major Facility Review

The existing Calpine Pittsburg Inc., facility (District Plant #11928) has submitted an application for a Title V operating permit in accordance with the requirements of Regulation 2, Rule 6.

Regulation 2, Rule 7: Acid Rain

The Delta Energy Center gas turbine units will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), DEC must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, “commence operation” includes the start-up of the unit’s combustion chamber.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NO_x burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines, HRSG duct burners, and auxiliary boilers 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. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.0034 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 5223 mg/l and corresponding maximum PM_{10} emission rate of 3.22 lb/hr, the proposed exempt 14-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the California

Energy Commission will impose conditions on construction activities that will require the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

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 emissions from the five proposed SCR systems will each 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

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at the DEC.

The use of solvents for cleaning and maintenance at the DEC 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

<u>Regulation 9, Rule 1, Sulfur Dioxide</u>

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). With maximum projected SO_2 emissions of < 1 ppm, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with section 302. The auxiliary boilers are expected to comply with these requirements through the exclusive use of natural gas.

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

The proposed combustion gas turbines (rated at 2003 MM BTU/hr HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm with nitrogen oxide emissions of 2.5 ppmvd @ 15% O_2. The HRSG duct burners have heat input ratings of less than 250 MM BTU/hr and therefore are not subject to this regulation. The proposed auxiliary boilers will comply with Regulation 9-3-303 with NO_x emissions of 9 ppmvd, @3% O_2. The proposed exempt emergency generator is not subject to this regulation since it has a heat input rating of 21 MM BTU/hr.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5. The proposed auxiliary boilers (rated at 256 MM BTU per hour) are expected to comply with Regulation 9, Rule 7 section 301.1 with NO_x emissions of 9 ppmv @ 3% O_2 and section 301.2 with expected CO emissions of 50 ppmvd @ 3% O_2 which is much less than the limit of 400 ppmvd @ 3% O_2.

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

The proposed exempt 300 hp fire pump diesel engine is exempt from the requirements of Regulation 9, Rule 8 per Regulation 9-8-111 since they will be operated less than 200 hours in any consecutive twelve month period. The owner/operator must comply with Regulation 9-8-502, “Recordkeeping” to qualify for this low usage exemption.

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

Because each of the proposed combustion gas turbines will be limited by permit condition to NO_x emissions of 2.5 ppmvd @ 15% O_2, they are expected to comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

IV Permit Conditions

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

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NO_x limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and NO_2 CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable O_2 content and the differing response times of the O_2 and NO_2 monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, SO_2, and PM_{10} mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to steady-state operation of each CTG/HRSG power train and the auxiliary boilers, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems in place and the auxiliary boilers will operate without their SCR systems and oxidation catalysts in place. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 18 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any short-term applicable ambient air quality standard.

Delta Energy Center
Permit Conditions

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.

Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
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 180 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 27(b) and 27(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 27(b) through 27(d) until termination of fuel flow to the Gas Turbine.
Auxiliary Boiler Start-up:	The lesser of the first 120 minutes of continuous fuel flow to an Auxiliary Boiler after fuel flow is initiated; or the period of time from fuel flow initiation until the Boiler achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 37(b) and 37(d).
Auxiliary Boiler Shutdown:	The lesser of the 30 minute period immediately prior the termination of fuel flow to the Auxiliary Boiler; or the period of time from non-compliance with any requirement listed in Conditions 37(a) through 37(d) until termination of fuel flow to the auxiliary boiler.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds. Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-1 (S-1 Gas Turbine and S-2 HRSG), emission point P-2 (S-3 Gas Turbine and S-4 HRSG), and emission point P-3 (S-5 Gas Turbine and S-6 HRSG) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-4 (S-7 Auxiliary Boiler #1) and emission point P-5 (S-8 Auxiliary Boiler #2), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the DE construction contractor to insure safe and reliable steady state

	operation of the gas turbines, heat recovery steam generators, steam turbine, auxiliary boiler, 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, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
DEC:	Delta Energy Center

Conditions for the Commissioning Period

1. The owner/operator of the Delta Energy Center (DEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators (HRSGs), and S-7 & S-8 Auxiliary Boilers to the maximum extent possible during the commissioning period. Conditions 1 through 18 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 19 through 73 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the combustors of S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators, and S-7 & S-8 Auxiliary Boilers shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-1, A-2, and A-3 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines and S-2, S-4, & S-6 Heat Recovery Steam Generators.

4. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-4 & A-6 Oxidation Catalysts and A-5 & S-7 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-7 & S-8 Auxiliary Boilers.

5. Coincident with the steady-state operation of A-1, A-2, & A-3 SCR Systems pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-

6) shall comply with the NO_x and CO emission limitations specified in conditions 27(a) through 27(d).

6. Coincident with the steady-state operation of A-5 & A-7 SCR Systems and A-4 & A-6 Oxidation Catalysts pursuant to conditions 4, 13, and 14, the Auxiliary Boilers (S-7 & S-8) shall comply with the NO_x and CO emission limitations specified in conditions 37(a) through 37(d).

7. The owner/operator of the DEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1, S-3, or S-5 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, auxiliary boilers, and steam turbine. 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 Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8) without abatement by their respective SCR Systems and/or oxidation catalysts.

8. During the commissioning period, the owner/operator of the DEC shall demonstrate compliance with conditions 10 through 14, 16, and 17 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

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

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8). 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.

9. The District-approved continuous monitors specified in condition 8 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8). After first firing of the turbines and auxiliary boilers, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

10. The total number of firing hours of S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System shall not exceed 300 hours

during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR 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 300 firing hours without abatement shall expire.

11. The total number of firing hours of S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR 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 300 firing hours without abatement shall expire.

12. The total number of firing hours of S-5 Gas Turbine and S-6 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR 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 300 firing hours without abatement shall expire.

13. The total number of firing hours of S-7 Auxiliary Boiler #1 without abatement of carbon monoxide emissions by A-4 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-5 SCR System shall not exceed 100 hours during the commissioning period. Such operation of S-7 Auxiliary Boiler without abatement by A-4 and/or A-5 shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 100 firing hours without abatement shall expire.

14. The total number of firing hours of S-8 Auxiliary Boiler #2 without abatement of carbon monoxide emissions by A-6 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-7 SCR System shall not exceed 100 hours during the commissioning period. Such operation of S-8 Auxiliary Boiler without abatement by A-6 and/or A-7 shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 100 firing hours without abatement shall expire.

15. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 49.

16. Combined pollutant mass emissions from the Gas Turbines (S-1, S-3, & S-5 and Heat Recovery Steam Generators (S-2, S-4, & S-6) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1, S-3, & S-5).

NO_x (as NO_2)	5,266 pounds per calendar day	400.4 pounds per hour
CO	16,272 pounds per calendar day	1,192 pounds per hour
POC (as CH_4)	686 pounds per calendar day	
PM_{10}	756 pounds per calendar day	
SO_2	82.5 pounds per calendar day	

17. Pollutant emissions from the Auxiliary Boilers (S-7 & S-8) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions that occur during Auxiliary Boiler start-ups.

NO_x (as NO_2)	428 pounds per calendar day	33 pounds per hour
CO	368 pounds per calendar day	22 pounds per hour
POC (as CH_4)	25.4 pounds per calendar day	
PM_{10}	96 pounds per calendar day	
SO_2	12.4 pounds per calendar day	

18. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 28. The source test shall determine NO_x, 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. Twenty calendar days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-1, S-3, & S-5) and the Heat Recovery Steam Generators (HRSGs; S-2, S-4, & S-6).

19. The Gas Turbines (S-1, S-3, and S-5) and HRSG Duct Burners (S-2, S-4, and S-6) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

20. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) shall not exceed 2,125 MM BTU per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

21. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 50,024 MM BTU per calendar day. (PSD for PM_{10})

22. The combined cumulative heat input rate for the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) shall not exceed 53,188,532 MM BTU per year. (Offsets)

23. The HRSG duct burners (S-2, S-4, and S-6) shall not be fired unless its associated Gas Turbine (S-1, S-3, and S-5, respectively) is in operation. (BACT for NO_x)

24. S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

25. S-3 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

26. S-5 Gas Turbine and S-6 HRSG shall be abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-3 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

27. The Gas Turbines (S-1, S-3, & S-5) and HRSGs (S-2, S-4, & S-6) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown.
(BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-3 (the combined exhaust point for the S-5 Gas Turbine and the S-6 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at emission points P-1, P-2, and P-3 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-1, P-2, and P-3 each shall not exceed 0.022 lb/MM BTU (HHV) of natural gas fired or 46.75 pounds per hour, averaged over any rolling 3-hour period. If compliance test results or continuous emissions monitoring data indicate that this level cannot be achieved during power steam augmentation operations, the owner/operator may seek approval for a higher CO mass emission limit for this operating mode, not to exceed 113.7 pounds per hour or 0.0535 lb/MM BTU of natural gas fired. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1, P-2, and P-3 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. If compliance test results or continuous emissions monitoring data indicate that this level cannot be achieved during power steam augmentation operations, the owner/operator may seek approval for a higher CO emission limit for this operating mode, not to exceed 24.3 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1, P-2, and P-3 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1, A-2, and A-3 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1, A-2, and A-3 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, and P-3 shall be determined in accordance with permit condition #52. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1, P-2, and P-3 each shall not exceed 5.33 pounds per hour or 0.00251 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1, P-2, and P-3 each shall not exceed 1.49 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 12 pounds per hour or 0.00565 lb/MM BTU of natural gas fired. (BACT)

28. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-3, and S-5) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Cold Start-Up (lb/start-up)	Hot Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18.1

Carbon Monoxide (CO)	2,514	902	44.1
Precursor Organic Compounds (as CH_4)	48	16	8

29. No more than one of the Gas Turbines (S-1, S-3, and S-5) shall be in start-up mode at any one time. (PSD)

30. The heat recovery steam generators (S-2, S-4, & S-6) and associated ducting shall be designed such that an oxidation catalyst can be readily installed and properly operated if deemed necessary by the APCO to insure compliance with the CO emission rate limitations of conditions 27(c) and 27(d). (BACT)

Conditions for Auxiliary Boilers (S-7 and S-8)

31. S-7 and S-8 Auxiliary Boilers shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

32. The heat input rate to each Auxiliary Boiler (S-7 and S-8) shall not exceed 256 million BTU per hour, averaged over any rolling 3-hour period. (Cumulative Increase)

33. The daily heat input rate to each Auxiliary Boiler (S-7 and S-8) shall not exceed 6,144 million BTU per day. (Cumulative Increase)

34. The combined cumulative heat input rate to S-7 Auxiliary Boiler #1 and S-8 Auxiliary Boiler #2 shall not exceed 582,234 million BTU per consecutive twelve month period. (Cumulative Increase)

35. S-7 Auxiliary Boiler #1 exhaust gas shall be abated by A-4 Oxidation Catalyst and A-5 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-7 and the A-5 catalyst bed has reached minimum operating temperature. (BACT)

36. S-8 Auxiliary Boiler #2 exhaust gas shall be abated by A-6 Oxidation Catalyst and A-7 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-8 and the A-7 catalyst bed has reached minimum operating temperature. (BACT)

37. S-7 and S-8 Auxiliary Boilers shall comply with requirements (a) through (h) listed below at all times, except during an auxiliary boiler start-up or shutdown. (BACT, PSD)

    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-4 (the exhaust point for S-7 Auxiliary Boiler #1, after abatement by A-4 Oxidation Catalyst and A-5 SCR System) shall not exceed 0.0108 lb/MM BTU (HHV) of natural gas fired or 2.9 pounds per hour, averaged over any rolling 3-hour period. Nitrogen oxide mass emissions (calculated as NO_2) at P-5 (the exhaust point for S-8 Auxiliary Boiler #2, after abatement by A-6 Oxidation Catalyst and A-7 SCR System) shall not exceed 0.0108 lb/MM BTU (HHV) of natural gas fired or 2.9 pounds per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at P-4 and P-5 each shall not exceed 9.0 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-4 (the exhaust point for S-7 Auxiliary Boiler #1, after abatement by A-4 Oxidation Catalyst) shall not exceed 0.0365 lb/MM BTU (HHV) of natural gas fired or 9.34 pounds per hour, averaged over any rolling 3-hour period. Carbon monoxide mass emissions at P-5 (the exhaust point for S-8 Auxiliary Boiler #2, after abatement by A-6 Oxidation Catalyst) shall not exceed 0.0365 lb/MM BTU (HHV) of natural gas fired or 9.34 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-4 and P-5 each shall not exceed 50 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) The precursor organic compound (POC) mass emission rates at P-4 and P-5 each shall not exceed 0.53 pounds per hour. (BACT for POC)

(f) The ammonia (NH_3) emission concentrations at P-4 and P-5 each shall not exceed 10 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-5 and A-7 SCR Systems. The correlation between the auxiliary boiler heat input rates, A-5 and A-7 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-4 and P-5 shall be determined in accordance with permit condition 55. (TRMP for NH_3)

(g) Sulfur dioxide (SO_2) mass emissions at P-4 and P-5 each shall not exceed 0.18 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-4 and P-5 each shall not exceed 2 pounds per hour or 0.0195 lb/MM BTU of natural gas fired. (BACT)

Conditions for Existing Sources
(S-67, S-70 & S-73 Gas Turbines and S-68, S-71, & S-74 Waste Heat Boilers)
S

38. Cumulative combined emissions from the Calpine/Dow Gas Turbines (S-67, S-70, and S-73) and Waste Heat Boilers (S-68, S-71, and S-74), including emissions generated during Gas Turbine Start-ups and Shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a) 18.5 tons of NO_x (as NO_2) per year (Offsets)
(b) 113.3 tons of CO per year (Cumulative increase)

(c) 4.7 tons of POC (as CH_4) per year (Offsets)
(d) 7.1 tons of PM_{10} per year (Offsets)
(e) 0.6 tons of SO_2 per year (Cumulative increase)

39. The cumulative combined heat input rate to the Calpine/Dow Gas Turbines (S-67, S-70, and S-73) and Waste Heat Boilers (S-68, S-71, and S-74) shall not exceed 2,060,652 million BTU per consecutive twelve-month period. (offsets)

40. The combined exhaust gas from S-67 Gas Turbine T-1 and S-68 Waste Heat Boiler #1 shall be abated by A-188 Selective Catalytic Reduction System whenever fuel is combusted at S-67 or S-68 and the A-188 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

41. The combined exhaust gas from S-70 Gas Turbine T-2 and S-71 Waste Heat Boiler #2 shall be abated by A-189 Selective Catalytic Reduction System whenever fuel is combusted at S-70 or S-71 and the A-189 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

42. The combined exhaust gas from S-73 Gas Turbine T-3 and S-74 Waste Heat Boiler #3 shall be abated by A-190 Selective Catalytic Reduction System whenever fuel is combusted at S-73 or S-74 and the A-190 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

43. The owner/operator of S-67, S-70, and S-73 Gas Turbines shall perform a source test to determine the NO_x, CO, and POC mass emission rates and the accuracy of the NO_x CEMs during gas turbine start-ups and shutdowns. The source test shall also determine the accuracy of the NO_x CEMs during gas turbine start-ups and shutdowns. If the NO_x CEMs do not accurately assess emissions during start-ups and/or shutdowns (as determined by APCO), then the District-approved source test results for NO_x mass emissions shall be utilized as an emission factor for the purposes of determining compliance with condition 38(a). The District-approved source test results for CO and POC mass emissions shall be utilized as emission factors for the purposes of determining compliance with conditions 38(b) and 38(c).
(offsets, cumulative increase)

44. The owner/operator of S-67, S-70, and S-73 Gas Turbines and S-68, S-71, and S-74 Waste Heat Boilers shall perform a District-approved source test for NO_x, POC, and PM_{10} mass emission rates in lb/hr and lb/MM BTU of natural gas fired at maximum operating rates at least once every 8,000 hours of turbine operation or every three calendar years, whichever comes first. (offsets, cumulative increase)

45. The owner/operator shall demonstrate compliance with conditions 38(a), 38(c), 38(d), and 39 by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-67, S-68, S-70, S-71, S-73, and S-74
(b) Oxygen (O_2) Concentrations and Nitrogen Oxides (NO_x) Concentrations at each of the following exhaust points: P-67, P-73, and P-79.

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

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

(c) Combined Heat Input Rate for S-67, S-68, S-70, S-71, S-73, and S-74
(d) Corrected NO_x concentrations, and NO_x mass emissions (as NO_2) at each of the following exhaust points: P-67, P-73, and P-79.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 45(c) and 45(d) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall utilize the data specified in 45(c) and 45(d) and the source test results specified in condition 44 to calculate and record the following data:

(e) total combined Heat Input Rate for the previous consecutive twelve month period
(f) on a monthly basis, the cumulative total NO_x mass emissions (as NO_2), POC mass emissions, and PM_{10} mass emissions for the previous consecutive twelve month period for all six sources (S-67, S-68, S-70, S-71, S-73, and S-74) combined.

(1-520.1, 9-9-501, Offsets)

Conditions for All New Sources
(S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 HRSGs, and S-7 & S-8 Auxiliary Boilers)

46. The combined heat input rate to the Gas Turbines (S-1, S-3, and S-5), HRSGs (S-2, S-4, and S-6), and Auxiliary Boilers (S-7 and S-8) shall not exceed 162,360 million BTU per calendar day. (PSD, CEC Offsets)

47. The cumulative heat input rate to the Gas Turbines (S-1, S-3, and S-5), HRSGs (S-2, S-4, and S-6), and Auxiliary Boilers (S-7 and S-8) combined shall not exceed 53,770,760 million BTU per year. (Offsets)

48. Total combined emissions from the Gas Turbines, HRSGs, and Auxiliary Boilers (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8), including emissions generated during Gas Turbine start-ups and

shutdowns, Auxiliary Boiler start-ups and shutdowns, shall not exceed the following limits during any calendar day:

(a)	2,123.5 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	13,204.4 pounds of CO per day	(PSD)
(c)	503.6 pounds of POC (as CH_4) per day	(CEQA)
(d)	876.3 pounds of PM_{10} per day	(PSD)
(e)	105.2 pounds of SO_2 per day	(BACT)

49. Cumulative combined emissions from the Gas Turbines, HRSGs, and Auxiliary Boilers (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8), including emissions generated during gas turbine start-ups, gas turbine shutdowns, auxiliary boiler start-ups, and auxiliary boiler shutdowns, shall not exceed the following limits during any consecutive twelve-month period:

(a)	279.7 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b)	1,116 tons of CO per year	(Cumulative Increase)
(c)	74.4 tons of POC (as CH_4) per year	(Offsets)
(d)	140.57 tons of PM_{10} per year	(Offsets, PSD)
(e)	18.6 tons of SO_2 per year	(Cumulative Increase)

50. The maximum projected annual toxic air contaminant emissions (per condition 52) from the Gas Turbines, HRSGs, and Auxiliary Boilers combined (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) shall not exceed the following limits:
    (a) 5,945 pounds of formaldehyde per year
    (b) 709 pounds of benzene per year
    (c) 120.5 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

    unless requirement (d) is satisfied:

    (d) 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 risk 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 the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

51. The owner/operator shall demonstrate compliance with conditions 20 through 23, 27(a) through 27(d), 28, 29, 32 through 34, 37(a) through 37(d), 46, 47, 48(a), 48(b), 49(a), and 49(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, S-5 and S-6 combined, S-7, and S-8.
(b) Oxygen (O_2) Concentrations, Nitrogen Oxides (NO_x) Concentrations, and Carbon Monoxide (CO) Concentrations at each of the following exhaust points: P-1, P-2, P-3, P-4, and P-5.
(c) Ammonia injection rate at A-1, A-2, A-3, A-5, and A-7 SCR Systems
(d) Steam injection rate at S-1, S-3, & S-5 Gas Turbine Combustors

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

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

(e) Heat Input Rate for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, S-5 and S-6 combined, S-7, and S-8.
(f) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-1, P-2, P-3, P-4, and P-5.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 51(e) and 51(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined, each Auxiliary Boiler, and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined.
(i) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.
(j) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, the Auxiliary Boilers, and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.
(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined and each Auxiliary Boiler.
(l) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.

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

52. To demonstrate compliance with conditions 27(f), 27(g), 27(h), 28, 48(c) through 48(e), and 49(c) through 49(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train and the auxiliary boilers. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 51, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

    (a) For each calendar day, POC, PM_{10}, and SO_2 Emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined); the Auxiliary Boilers; and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.
    (b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.

    (Offsets, PSD, Cumulative Increase)

53. To demonstrate compliance with Condition 50, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 32,912,920 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of Heat Input) determined by any source test at the Gas Turbine, HRSG, or Auxiliary Boilers. (TRMP)

54. Within 60 days of start-up of the DEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 27(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-1, A-2, or A-3 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1, P-2, or P-3. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 27(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

55. Within 60 days of start-up of the DEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1, P-2, and P-3 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 27(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 27(c) and

(d), and to verify the accuracy of the continuous emission monitors required in condition 50. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

56. Within 60 days of start-up of the DEC, the owner/operator shall conduct a District-approved source test on exhaust point P-4 or P-5 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 37(e). The source test shall determine the correlation between the heat input rates of an auxiliary boilers and the A-4 or A-5 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-4, or P-5. The source testing shall be conducted over the expected operating range of the auxiliary boiler (including, but not limited to 10%, 50%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 37(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

57. Within 60 days of start-up of the DEC and on an annual basis thereafter, the owner/operator shall conduct a District approved source test on exhaust point P-4 and P-5 while each Auxiliary Boiler (S-7 and S-8) is operating at maximum load to determine compliance with the emission limitations of Condition 37, parts (a) through (e), (g), & (h), while each Auxiliary Boiler (S-7 and S-8) is operating at minimum load to determine compliance with Condition 37, parts (c), (d), & (f), and to verify the accuracy of the continuous emission monitors required in condition 51. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

58. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

59. Within 60 days of start-up of the DEC and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust

point P-1, P-2, or P-3 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 50. Unless the requirements of condition 59(b) have been met, the owner/operator shall determine the formaldehyde, benzene, and Specified PAH emission rates (in pounds/MM BTU). If any of the above pollutants are not detected (below the analytical detection limit), the emission concentration for that pollutant shall be deemed to be one half (50%) of the detection limit concentration. (TRMP)

(a) The owner/operator shall calculate the maximum projected annual emission rate for each pollutant by multiplying the pollutant emission rate (in pounds/MM BTU; determined by source testing) by 53,770,760 MM BTU/year.

(b) If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to part (a) for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	221 pounds/year
Formaldehyde	≤	1,834 pounds/year
Specified PAH's	≤	38 pounds/year

(TRMP)

60. The owner/operator of the DEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

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

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

63. The stack height of emission points P-1, P-2, and P-3 shall each be at least 144 feet above grade level at the stack base. The stack height of emission points P-4 and P-5 shall each be at least 115 feet above grade level at the stack base. (PSD, TRMP)

64. The Owner/Operator of DEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval.
(Regulation 1-501)

65. Within 180 days of the issuance of the Authority to Construct for the DEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 54 through 57, and 59. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

66. Prior to the issuance of the BAAQMD Authority to Construct for the Delta Energy Center, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 235.62 tons/year of Nitrogen Oxides, 75.3 tons/year of Precursor Organic Compounds, and 127.37 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1 are under their control through enforceable contract or option to purchase agreements or equivalent binding legal documents. (Offsets)

67. Prior to the start of construction of the Delta Energy Center, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 235.62 tons/year of Nitrogen Oxides, 75.3 tons/year of Precursor Organic Compounds, and 127.37 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1. (Offsets)

68. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of DEC shall submit an application to the District for a significant modification to the DEC's Federal (Title V) Operating Permit within 12 months of the initial operation of the gas turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), or Auxiliary Boilers (S-7 & S-8). (Regulation 2-6-404.3)

69. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Delta Energy Center shall submit an application for a Title IV operating permit at least 24 months prior to the initial operation of any of the gas turbines (S-1, S-3, & S-5) or HRSGs (S-2, S-4, & S-6). (Regulation 2, Rule 7)

70. The Delta Energy Center shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

71. The owner/operator shall take monthly samples of the natural gas combusted at the DEC. The samples shall be analyzed for sulfur content using District-approved laboratory methods. The test results shall be retained on site for a minimum of five years from the test date. (cumulative increase)

72. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0006%. 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 5,233 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

73. 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 initial operation of the Delta Energy Center, 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 a satisfactory manner. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM_{10} emission rate from the cooling tower to verify continued compliance with the vendor-guaranteed drift rate specified in condition #71. (PSD)

V Recommendation

The APCO has concluded that the proposed Delta Energy Center power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-1 Combustion Gas Turbine #1, General Electric 7251FA or Westinghouse 501FD; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-1 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, General Electric 7251FA or Westinghouse 501FD; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-2 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-2 Selective Catalytic Reduction System

S-5 Combustion Gas Turbine #3, General Electric 7251FA or Westinghouse 501FD; 2,003 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-3 Selective Catalytic Reduction System

S-6 Heat Recovery Steam Generator #3, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-3 Selective Catalytic Reduction System

S-7 Auxiliary Boiler #1, equipped with low-NO_x burners, 256 MM BTU per hour, abated by A-4 Oxidation Catalyst and A-5 Selective Catalytic Reduction System

S-8 Auxiliary Boiler #2, equipped with low-NO_x burners, 256 MM BTU per hour, abated by A-6 Oxidation Catalyst and A-7 Selective Catalytic Reduction System

Pursuant to District Regulation 2-3-404, this document has fulfilled the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407.

Appendix A

Emission Factor Derivations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to calculate criteria pollutant and toxic air contaminant emissions.

standard temperature[a]:	70^{o}F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8600 dscf/MM BTU
natural gas higher heating value:	1030 BTU/dscf

[a]BAAQMD standard conditions per Regulation 1, Section 228.

[b]based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Based upon typical composition of utility-grade natural gas in bay area.

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

Table A-1
Controlled Regulated Air Pollutant Emission Factors
(lb/MM BTU)

Pollutant	Source				
	Gas Turbine	HRSG	Gas Turbine & HRSG Combined	Auxiliary Boiler	
				100% Load	10% Load
Nitrogen Oxides (as NO_2)	0.00904[a]	N/S	0.00904[a]	0.0108[c]	0.0108
Carbon Monoxide	0.022[b]	0.1	0.022[b]	0.0365[d]	0.0365
Precursor Organic Compounds	0.00251	N/S	0.00251[e]	0.0021	0.0042
Particulate Matter (PM_{10})	0.005	N/S	0.00565	0.00781	0.0195
Sulfur Dioxide	0.0007	0.0007	0.0007	0.0007	0.0007

[a]based upon the permit condition emission limit of 2.5 ppmvd NO_x @ 15% O_2 that reflects the use of dry low-NO_x combustors at the CTG, low-NO_x burners at the HRSG, and abatement by the proposed A-1, A-2, and A-3 Selective Catalytic Reduction Systems with ammonia injection

[b]based upon the permit condition emission limit of 10 ppmvd CO @ 15% O_2

[c]based upon the permit condition emission limit of 9 ppmvd NO_x @ 3% O_2

[d]based upon the permit condition emission limit of 50 ppmvd CO @ 3% O_2

[e]based upon ARB Guidance Policy BACT determination of 2 ppmvd POC @ 15% O_2

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined NO_x emissions from the CTG and HRSG will be limited to 2.5 ppmv, dry @ 15% O_2. This emission limit will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.5 ppmvd)(20.95 - 0)/(20.95 - 15) = 8.8 ppmv NO_x, dry @ 0% O_2

($8.8/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8600 dscf/MM BTU)

= **0.00904 lb NO_2/MM BTU**

The NO_x mass emission rate based upon the maximum firing rate of the CTG alone is calculated as follows:

(0.00904 lb/MM BTU)(2,003 MM BTU/hr) = **18.1 lb NO_x/hr**

The NO_x mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.00904 lb/MM BTU)(2,125 MM BTU/hr) = **19.2 lb NO_x/hr**

Auxiliary Boilers

The auxiliary boiler NO_x emissions will be limited to the BACT level of 9 ppmv, dry @ 3% O_2. This concentration is converted to a mass emission factor as follows:
(9 ppmvd)(20.95 - 0)/(20.95 - 3) = 10.5 ppmv, dry @ 0% O_2

$[(10.5/10^6)/385.3$ dscf/lbmol](46.01 lb NO_2/lbmol)(8600 dscf/MM BTU)

= **0.0108 lb NO_2/MM BTU**

The corresponding NO_x mass emission rate based upon the maximum firing rate of an auxiliary boiler is calculated as follows:

(0.0108 lb/MM BTU)(256 MM BTU/hr) = **2.76 lb NO_x/hr**

CARBON MONOXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled CO emission limit of 10 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up, shutdown, and HRSG duct burner firing with steam injection power augmentation. The emission factor corresponding to this emission concentration is calculated as follows:

(10 ppmv)(20.95 - 0)/(20.95 - 15) = 35.21 ppmv, dry @ 0% O_2

$(35.21/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= **0.022 lb CO/MM BTU**

The CO mass emission rate based upon the maximum firing rate of the CTG alone is calculated as follows:

(0.022 lb/MM BTU)(2,003 MM BTU/hr) = **44.07 lb CO/hr**

The CO mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.022 lb/MM BTU)(2,125 MM BTU/hr) = **46.75 lb CO/hr**

During duct burner firing when steam injection power augmentation occurs at the gas turbine combustors, the combined CTG/HRSG CO emission concentration will be limited to 24.3 ppmvd @ 15% O_2. The emission factor corresponding to this emission concentration is calculated as follows:

(24.3 ppmv)(20.95 - 0)/(20.95 - 15) = 85.56 ppmv, dry @ 0% O_2

$(85.56/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= **0.0535 lb CO/MM BTU**

The CO mass emission rate during duct burner firing with steam injection power augmentation is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.0535 lb/MM BTU)(2,125 MM BTU/hr) = **113.7 lb CO/hr**

Auxiliary Boiler

Pursuant to current BACT Guidelines and vendor guarantees, the auxiliary boiler will achieve a CO emission concentration of 50 ppmv, dry @ 3% O_2. The emission factor corresponding to this emission concentration is calculated as follows:

(50 ppmv)(20.95 - 0)/(20.95 - 3) = 58.35 ppmv, dry @ 0% O_2

($58.35/10^6$)(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= **0.0365 lb CO/MM BTU**

The corresponding CO mass emission rate in lb/hr based upon the maximum firing rate of an auxiliary boiler is calculated as follows:

(0.0365 lb/MM BTU)(256 MM BTU/hr) = **9.34 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Combustion Gas Turbine

Westinghouse has guaranteed a maximum POC (non-methane/ethane hydrocarbon) emission rate of 8 lb/hour for full load operation of the CTG alone and 12 lb/hr for full load operation of the CTG with duct burner firing.

This converts to an emission factor as follows:

POC = (8 lb/hr)/(2,003 MM BTU/hr) = **0.004 lb/MM BTU**

Converting to a concentration yields:

$[(0.004\ lb/MM\ BTU)(10^6)(385.3\ dscf/lbmol)]/[(16\ lb\ CH_4/lb\text{-}mol)(8600\ dscf/MM\ BTU)]$

$= 11.2$ ppmvd @ 0% O_2

Converting to 15% O_2:

(11.2 ppmvd)(20.95 – 15)/(20.95) = 3.2 ppmvd @ 15% O_2

<u>Combustion Gas Turbine and Heat Recovery Steam Generator Combined</u>

Westinghouse, the turbine vendor, has guaranteed a maximum POC (non-methane/ethane hydrocarbon) emission rate of 12 lb/hr for full load operation of the CTG with duct burner firing. This emission rate is based upon an HRSG duct burner POC emission factor of 0.02 lb/MM BTU, a maximum rated heat input of 200 MM BTU/hr and a corresponding mass emission rate of 4 lb/hr.

This converts to an emission factor of:

(12 lb/hr)/(2,125 MM BTU/hr) = **0.00565 lb/MM BTU**

Converting to a concentration yields:

$[(0.00565\ lb/MM\ BTU)(10^6)(385.3\ dscf/lbmol)]/[(16\ lb\ CH_4/lb\text{-}mol)(8600\ dscf/MM\ BTU)]$

$= 15.82$ ppmvd @ 0% O_2

Converting to 15% 0_2:

(15.82 ppmvd)(20.95 – 15)/(20.95) = 4.5 ppmvd @ 15% O_2

In response to comments for EPA and ARB, the applicant has agreed to a combined POC emission rate of 2 ppmvd @ 15% O_2. This converts to a mass emission rate of:

(2/4.5)(12 lb/hr) = **5.33 lb/hr**

Which corresponds to a POC emission factor of :

(2/4.5)(0.00565 lb/MM BTU) = **0.00251 lb/MM BTU**

<u>Auxiliary Boiler</u>

The maximum POC (as CH_4) emission factor for the auxiliary boiler is based upon a vendor guarantee of 10 ppmvd @ 3% O_2 at minimum load.
The **minimum load POC emission factor** is therefore:

(10 ppmv)(20.95 - 0)/(20.95 - 3) = 11.67 ppmv, dry @ 0% O_2

$(11.67/10^6)$(lbmol/385.3 dscf)(16 lb CH_4/lb-mol)(8600 dscf/MM BTU)

= **0.0042 lb POC/MM BTU**

The corresponding POC mass emission rate in lb/hr based upon the minimum load (10%) firing rate of an auxiliary boiler is calculated as follows:

(0.0042 lb/MM BTU)(256 MM BTU/hr)(0.10) = **0.11 lb POC/hr**

At full load, the auxiliary boiler will operate more efficiently, resulting in more complete combustion and a POC emission rate of 0.53 lb/hr, per vendor specifications.

This converts to a **full load POC emission factor** of:

(0.53 lb/hr)/(256 MM BTU/hr) = **0.0021 lb/MM BTU**

Converting to a concentration yields:

[(0.0021 lb/MM BTU)(10^6)(385.3 dscf/lbmol)]/[(16 lb CH_4/lb-mol)(8600 dscf/MM BTU)]

= 5.88 ppmvd @ 0% O_2

Converting to 3% O_2:

(5.88 ppmvd)(20.95 – 3)/(20.95) = 5 ppmvd @ 3% O_2

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Combustion Gas Turbine

Westinghouse has guaranteed a PM_{10} emission rate of 10 lb/hr at maximum load for the gas turbine. The corresponding PM_{10} emission factor is therefore:

(10 lb PM_{10}/hr)/(2,003 MM BTU/hr) = **0.005 lb PM_{10}/MM BTU**

The following stack data will be used to calculate the grain loading at standard conditions for full load CTG operation without duct burner firing to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	10 lb/hr
typical flow rate:	789,037 dscfm @ 13.44% O_2

Converting to grains/dscf:

($10\ lb\ PM_{10}/hr$)($1\ hr/60\ min$)($7000\ gr/lb$)/($789{,}037\ dscfm$) = 0.0015 gr/dscf
Converting to 6% O_2 basis:

(0.0015 gr/dscf)[(20.95 - 6)/(20.95 – 13.44)] = 0.003 gr/dscf @ 6% O_2

Combustion Gas Turbine and HRSG Combined

The PM_{10} emission factor is based upon the Westinghouse vendor guarantee of 12 lb/hr at the maximum combined firing rate of 2,125 MM BTU/hr. The corresponding PM_{10} emission factor is therefore:

(12 lb PM_{10}/hr)/(2,125 MM BTU/hr) = **0.00565 lb PM_{10}/MM BTU**

It is assumed that this PM_{10} emission factor includes secondary PM_{10} formation of particulate sulfates.

The following stack data will be used to calculate the grain loading for simultaneous CTG and HRSG operation at standard conditions to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	12 lb/hr
typical flow rate:	713,457 dscfm @ 12.14% O_2

Converting to grains/dscf:

(12 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(713,457 dscfm) = 0.002 gr/dscf

Converting to 6% O_2 basis:

(0.002 gr/dscf)[(20.95 - 6)/(20.95 – 12.14)] = 0.0034 gr/dscf @ 6% O_2

Auxiliary Boilers

The PM_{10} emission factor is based upon a vendor guarantee of 2 lb/hr at maximum load.

The **PM_{10} emission factor** is therefore:

(2 lb PM_{10}/hr)/(256 MM BTU/hr) = **0.00781 lb PM_{10}/MM BTU**

At minimum load (10%), the PM_{10} emission rate will be 0.5 lb/hr per vendor specifications.

This converts to an emission factor of:

(0.5 lb/hr)/(25.6 MM BTU/hr) = **0.0195 lb PM_{10}/MM BTU**

The following stack data will be used to calculate the grain loading at standard conditions for minimum load auxiliary boiler operation to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	0.5 lb/hr
typical flow rate:	5,699 dscfm @ 7.47% O_2

Converting to grains/dscf:

(0.5 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(5,699 dscfm) = 0.01 gr/dscf

Converting to 6% O_2 basis:

(0.01 gr/dscf)[(20.95 - 6)/(20.95 – 7.47)] = 0.011 gr/dscf @ 6% O_2

The following stack data will be used to calculate the grain loading at standard conditions for full load auxiliary boiler operation to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	2 lb/hr
typical flow rate:	42,159 dscfm @ 3% O_2

Converting to grains/dscf:

(2 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(42,159 dscfm) = 0.0055 gr/dscf

Converting to 6% O_2 basis:

(0.0055 gr/dscf)[(20.95 - 6)/(20.95 – 3)] = 0.0046 gr/dscf @ 6% O_2

SULFUR DIOXIDE EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon a maximum natural gas sulfur content of 0.25 gr/100 scf and a higher heating value of 1030 BTU/scf as specified by PG&E.

The sulfur emission factor is calculated as follows:

(0.25 gr S/100 scf)(1 scf/1,030 BTU)(2 gr SO_2/1 gr S)(1 lb/7000 gr)(10^6 BTU/MM BTU)

= **0.0007 lb SO_2/MM BTU**

The corresponding mass SO_2 emission rate at the maximum combined firing rate of 2,125 MM BTU/hr is:

(0.0007 lb SO_2/MM BTU)(2,125 MM BTU/hr) = 1.49 lb/hr

This is converted to an emission concentration as follows:

(0.0007 lb SO_2/MM BTU)(385.3 dscf/lbmol)(10^6)(lb-mol/64.06 lb SO_2)(MM BTU/8600 dscf)

= 0.49 ppmvd SO_2 @ 0% O_2

which is equivalent to:

(0.49 ppmvd)(20.95 - 15)/20.95 = 0.14 ppmv SO_2, dry @ 15% O_2

Auxiliary Boiler

As in the case of the CTG and HRSG, the maximum sulfur content of natural gas will be limited to 0.25 gr/100 scf. The **SO_2 emission factor** for the auxiliary boiler is therefore also **0.0007 lb SO_2/MM BTU**.

This converts to a SO_2 mass emission rate of:

(0.0007 lb SO_2/MM BTU)(256 MM BTU/hr) = 0.18 lb SO_2/hr

Toxic Air Contaminants

The following toxic air contaminant emission factors were used to calculate worst-case emissions rates used for air pollutant dispersion models that estimate the resulting increased health risk to the maximally exposed population. To ensure that the risk is properly assessed, the emission factors are conservative and may overestimate actual emissions.

Table A-2 TAC Emission Factors[a] for Gas Turbines

Contaminant	Emission Factor (lb/MM scf)
Acetaldehyde[c]	6.86E-02
Acrolein	2.37E-02
Ammonia[b]	12.2
Benzene[c]	1.36E-02
1,3-Butadiene[c]	1.27E-04
Ethylbenzene	1.79E-02
Formaldehyde[c]	1.10E-01
Hexane	2.59E-01
Naphthalene	1.66E-03
PAHs[c]	2.32E-03
Propylene	7.70E-01
Propylene Oxide[c]	4.78E-02
Toluene	7.10E-02
Xylene	2.61E-02

[a]the highest of either Ventura County APCD or CATEF emission factors for gas turbines

[b]based upon maximum allowable ammonia slip of 10 ppmv, dry @ 15% O_2 for A-1, A-2, and A-3 SCR Systems

[c]carcinogenic compound

Table A-3 TAC Emission Factors[a] for Auxiliary Boilers

Contaminant	Emission Factor (lb/MM scf)
Acetaldehyde[b]	0.0089
Acrolein	0.0008
Ammonia[c]	4.4
Benzene[b]	0.00431
Ethylbenzene	0.002
Formaldehyde[b]	0.221
Hexane	0.0013
Naphthalene	0.0003
PAHs[b]	0.0004
Propylene	0.1553
Toluene	0.0078
Xylene	0.0058

[a]the highest of either Ventura County APCD or CATEF emission factors for industrial boilers

[b]carcinogenic compound

[c]based upon maximum allowable ammonia slip of 10 ppmv, dry @ 3% O_2 for A-5 and A-7 SCR Systems

Table A-4
TAC Emission Factors[a] for Cooling Towers

Contaminant	Emission Factor (lb/hr)
Aluminum	4.5E-05
Arsenic[b]	1.8E-06
Silver	2.3E-06
Barium	5.4E-06
Beryllium[b]	4.5E-06
Cadmium[b]	4.5E-06
Chloride	0.1027
Hexavalent chromium[b]	2.3E-06
Copper	3.2E-06
Fluoride	3.2E-04
Lead[b]	9.9E-06
Magnesium	1.2E-02
Manganese	6.1E-05
Mercury	9.1E-08
Selenium[b]	3.2E-06
Silica[b]	1.2E-05
Sodium hydroxide	3.2E-06
Sulfate	8.8E-02
Zinc	5.6E-06

[a]based upon 24 hr/day, 365 day/yr operation of cooling towers at maximum flow rate

[b]carcinogenic compound

AMMONIA EMISSION FACTOR

<u>Combustion Gas Turbine & Heat Recovery Steam Generator</u>

Each CTG/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 10 ppmvd @ 15% O_2.

NH_3 emission concentration limit:	10 ppmvd @ 15% O_2
Dry gas flow rate (w/o duct burner):	789,037 dscfm @ 13.44% O_2 by volume
Dry gas flow rate (w/duct burner):	713,457 dscfm @ 12.14% O_2 by volume

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

(10 ppmvd)(20.95 – 12.14)/(20.95 – 15) = 14.81 ppmvd @ 12.14% O_2

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

(14.81 ppmvd/10^6)(713,383 dscfm)(60 min/hr)(lb-mol/385.3 dscf)(17 lb NH_3/lbmol)

= **27.97 lb NH_3/hr**

Based upon the maximum heat input for a CTG of 2,003 MM BTU/hr, this mass emission rate converts to the following emission factor:

(27.97 lb NH_3/hr)/(2,003 MM BTU/hr) = **0.014 lb NH_3/MM BTU**
= 14 lb NH_3/MM scf

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

(10 ppmvd)(20.95 – 13.44)/(20.95 – 15) = 12.62 ppmvd @ 12.14% O_2

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

(12.62 ppmvd/10^6)(789,037 dscfm)(60 min/hr)(lb-mol/385.3 dscf)(17 lb NH_3/lbmol)

= **26.36 lb NH_3/hr**

Based upon the maximum heat input for a CTG of 2,003 MM BTU/hr, this mass emission rate converts to the following emission factor:

(26.36 lb NH_3/hr)/(2,003 MM BTU/hr) = **0.0132 lb NH_3/MM BTU**
= 13.2 lb NH_3/MM scf

Auxiliary Boilers

Each auxiliary boiler will be subject to a maximum ammonia exhaust concentration limit of 10 ppmvd @ 3% O_2.

NH_3 emission concentration limit:	10 ppmvd @ 3% O_2
Full load exhaust gas flow rate:	42,159 dscfm @ 2.99% O_2
Minimum load exhaust gas flow rate:	5,699 dscfm @ 7.47% O_2

Correcting to actual oxygen content at full load:

$(10\ \text{ppmvd})(20.95 - 2.99)/(20.95 - 3) = 10\ \text{ppmvd} @ 2.99\%\ O_2$

The ammonia mass emission rate at full load is therefore:

$(10\ \text{ppmvd}/10^6)(42{,}159\ \text{dscfm})(60\ \text{min/hr})(\text{lb-mol}/385.3\ \text{dscf})(17\ \text{lb}\ NH_3/\text{lbmol})$

= **1.12 lb NH_3/hr**

Based upon the maximum heat input for an auxiliary boiler of 256 MM BTU/hr, this mass emission rate converts to the following emission factor:

(1.12 NH_3/hr)/(256 MM BTU/hr) = **0.0044 lb NH_3/MM BTU**
= 4.4 lb NH_3/MM scf

Correcting to actual oxygen content at minimum load:

$(10\ \text{ppmvd})(20.95 - 7.47)/(20.95 - 3) = 7.51\ \text{ppmvd} @ 7.47\%\ O_2$

The corresponding ammonia mass emission rate at minimum load (10%) is therefore:

$(7.51\ \text{ppmvd}/10^6)(5{,}699\ \text{dscfm})(60\ \text{min/hr})(\text{lb-mol}/385.3\ \text{dscf})(17\ \text{lb}\ NH_3/\text{lbmol})$

= **0.11 lb NH_3/hr**

Based upon the minimum heat input for an auxiliary boiler of 25.6 MM BTU/hr, this mass emission rate converts to the following emission factor:

(0.11 lb NH_3/hr)/(25.6 MM BTU/hr) = **0.0043 lb NH_3/MM BTU**
= 4.3 lb NH_3/MM scf

Appendix B

Emission Calculations

This appendix discusses the assumptions underlying the emission calculations used to determine the maximum regulated air pollutant and toxic air contaminant emission rates for the Delta Energy Center.

Individual and combined heat input rate limits for the Gas turbines, HRSGs, and auxiliary boilers are given below in **Table B-1**. These are the basis of permit conditions limiting heat input rates.

Table B-1 Maximum Allowable Heat Input Rates

Source	MM BTU/hour-source	MM BTU/day-source	MM BTU/year-source
S-1, S-3, and S-5 CTGs	2,003	48,065[a]	17,543,652[b]
S-1 CTG and S-2 HRSG S-3 CTG and S-4 HRSG S-5 CTG and S-6 HRSG	2,125[c]	50,024[d]	17,729,280[e]
S-7 Auxiliary Boiler	256	6,144	351,960[f,h]
S-8 Auxiliary Boiler	256	6,144	236,960[g,h]

[a]based upon specified maximum rated heat input of 2002.7 MM BTU/hr and 24 hour per day operation

[b]based upon 8,760 hours of operation at full load (2002.7 MM BTU/hr)

[c]maximum combined firing rate for gas turbine and HRSG duct burners

[d]based upon maximum duct burner firing of 16 hours per day; calculated as:

(16 hr/day)(2,125 MM BTU/hr) + (8 hr/day)(2,003 MM BTU/hr) = 50,024 MM BTU/day

[e]based upon maximum annual duct burner firing of 1,500 hr/year-HRSG; calculated as:

(1,500 hr/yr)(2,125 MM BTU/hr) + (7,260 hr/yr)(2,003 MM BTU/hr)
= 17,729,280 MM BTU/year

[f]based upon 540 hr/year of full load operation and 8,220 hr/year of operation at 10% load; calculated as:

(540 hr/yr)(256 MM BTU/hr) + (8,220 hr/yr)(26 MM BTU/hr) = 351,960 MM BTU/yr

[g]based upon 40 hr/year of full load operation and 8,720 hr/year of operation at 10% load; calculated as:

(40 hr/yr)(256 MM BTU/hr) + (8,720 hr/yr)(26 MM BTU/hr) = 236,960 MM BTU/yr

[h]will be subject to a combined permit condition limit of 582,234 MM BTU/year for operator flexibility

Table B-2 Maximum Annual Facility Emissions from Permitted Sources
(ton/yr)

Source	NO_2	CO	POC	PM_{10}	SO_2
S-1 CTG and S-2 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-3 CTG and S-4 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-5 CTG and S-6 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-7 Auxiliary Boiler	1.88	6.36	0.59	2.59	0.12
S-8 Auxiliary Boiler	1.26	4.26	0.48	2.216	0.08
S-67, S-70, & S-73 Gas Turbines and S-68, S-71, & S-74 Waste Heat Boilers[b]	18.5	113.3	4.7	7.1	0.6
Total Permitted Emissions[c]	**298.17**	**1,229.36**	**79.37**	**147.67**	**19.22**

[a]includes gas turbine start-up and shutdown emissions;

[b]proposed permit condition emission limitations

[c]includes existing and proposed permitted sources

B-1.0 Gas Turbine Start-Up and Shutdown Emission Rate Calculations

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound emission rates from a gas turbine occur during start-up and shutdown periods. The PM_{10}, sulfur dioxide, ammonia, and toxic compound emissions are a function of fuel use rate only and do not exceed typical full load emission rates during start-up.

Table B-3 Gas Turbine Start-Up Emission Rates (lb/start-up)

Pollutant	Cold Start-Up[a]	Hot Start-Up[b]
NO_x (as NO_2)	240	80
CO	2,514[c]	902
UHC (as CH_4)	48	16
PM_{10}[d]	36	12
SO_x (as SO_2)[e]	4.2	1.4

[a]cold start not to exceed three hours

[b]hot start not to exceed one hour

[c]based upon emission rate of 838 lb CO/hour per Sutter Power Project

[d]as a conservative estimate, based upon full load emission factor of 0.00565 lb PM_{10}/MM BTU and maximum combined heat input rate of 2,125 MM BTU/hr

[e]based upon full load emission factor of 0.0007 lb SO_2/MM BTU and maximum heat input rate of 2,003 MM BTU/hr

Based upon source test data of Crockett Cogeneration gas turbine, the applicant has assumed that turbine shutdown emission rates for NO_x, CO, and POC do not exceed full load emission rates. **Table B-4** lists gas turbine startup emission rates and Table B-5 is a comparison of baseload emission rates and shutdown emission rates based upon source test data.

Table B-4 Gas Turbine Shutdown Emission Rates (lb/hr)

Pollutant	Baseload Emission Rate	Crockett Cogeneration Source Tests[a]
NO_x	18.1	5.2
CO	44.1	29.5
UHC (as CH_4)	8.0	2.6

[a]G.E. Frame 7F turbine; testing occurred June 1997

B-1.1 START-UP EMISSION RATE CALCULATIONS:

Hot Start-Up

- Total duration: 1 hour

NITROGEN OXIDES (as NO_2)

NO_x emission rate: 80 lb/hr

NO_2 = (80 lb/hr)(1 hr/hot start)
= **80 lb/hot start**

CARBON MONOXIDE

CO emission rate: 902 lb/hr
(Sutter Power Plant emission rate from Westinghouse)

CO = (902 lb CO/hr)(1 hr/hot start)
= **902 lb/hot start**

PRECURSOR ORGANIC COMPOUNDS

POC emission rate: 16 lb/hr
(twice the full load turbine emission rate)

POC = (16 lb POC/hr)(1 hr/hot start)
= **16 lb/hot start**

PARTICULATE MATTER (as PM_{10})

(a) PM_{10} emissions are not increased during start-up
(b) PM_{10} emission factor based upon full load operation w/duct burner firing (emission rate of 12 lb/hr)

CTG PM_{10} emissions during a start-up are therefore:

PM_{10} = (12 lb PM_{10}/hr)(1 hr/hot start)
= **12 lb PM_{10}/ hot start**

SULFUR DIOXIDE

(a) SO_2 emissions are not increased during start-up
(b) based upon full load emission factor of 0.0007 lb SO_2/MM BTU and maximum heat input of 2,003 MM BTU/hr

CTG SO_2 emissions during a start-up are therefore:

SO_2 = (0.0007 lb SO_2/MM BTU)(2,003 MM BTU/hr)(1 hr/hot start)
= **1.4 lb SO_2/hot start**

Cold Start-Up

- Total Duration of cold start: 3 hours

NITROGEN OXIDES (as NO_2)

NO_x emission rate: 80 lb/hr

NO_2 = (80 lb/hr)(3 hr/cold start)
= **240 lb/cold start**

CARBON MONOXIDE

CO emission rate: 838 lb/hr
(Sutter Power Project estimate per Westinghouse)

CO = (838 lb/hr)(3 hr/cold start)
= **2,514 lb/cold start**

PRECURSOR ORGANIC COMPOUNDS

POC emission rate: 16 lb/hr
(twice the full load turbine emission rate)

POC = (16 lb POC/hr)(3 hr/cold start)
= **48 lb/cold start**

PARTICULATE MATTER (as PM_{10})

PM_{10} emissions are not increased during start-up
PM_{10} emission rate during start-up equals maximum baseload emission rate of 12 lb/hr

CTG PM_{10} emissions during a start-up are therefore:

PM_{10} = (12 lb PM_{10}/hr)(3 hr/cold start)
= **36 lb PM_{10}/cold start**

SULFUR DIOXIDE

(a) SO_2 emissions are not increased during start-up
(b) based upon full load emission factor of 0.0007 lb SO_2/MM BTU and maximum heat input of 2,003 MM BTU/hr

CTG SO_2 emissions during a start-up are therefore:

SO_2 = (0.0007 lb SO_2/MM BTU)(2,003 MM BTU/hr)(3 hr/cold start)
= **4.2 lb SO_2/cold start**

B-2.0 Typical Operating Scenarios and Regulated Air Pollutant Emissions

New Gas Turbines and HRSGs

The CTG/HRSG emission rates shown in **Table B-5** are the basis of permit condition limits and emission offset requirements and were also used as inputs for the ambient air quality impact analysis. To provide maximum operational flexibility, no limitations will be imposed on the type or quantity of turbine start-ups. Instead, the facility must comply with consecutive twelve month mass limits at all times. The emission estimates are based upon the following operating envelope.

- 6,844 hours of baseload (100% load) operation per year for each CTG @ 30°F
- 1,500 hours of duct burner firing per HRSG per year with steam injection power augmentation at CTG turbine combustors
- 156 one-hour hot start-ups per CTG per year
- 52 three-hour cold start-ups per CTG per year

Table B-5 Maximum Annual Regulated Air Pollutant Emissions for CTGs and HRSGs

Source (Operating Mode)	NO_2 (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)
S-1, S-3, & S-5 CTGs (780 total hot start-ups)	62,400	703,560	12,480	9,360	1,092
S-1, S-3, & S-5 CTGs (156 total cold start-ups)	37,400	392,184	7,488	5,616	655.2
S-1, S-3, & S-5 CTGs (20,532 total hours[a] @ 100% load)	371,775.4[b]	904,763[b]	103,225.2[b]	205,628	28,788
S-1, S-3, & S-5 CTGs and S-2, S-4, & S-5 HRSGs (4,500 total hours[a] w/duct burner firing and steam injection power augmentation)	81,482[c]	210,375[c]	24,001.9[c]	50,926.3[d]	6,309.5[c]
Total Emissions (lb/yr)	553,057.4	2,210,882	147,195.1	271,530.3	36,844.7
(ton/yr)	**276.53**	**1,105.44**	**73.6**	**135.76**	**18.42**

[a]total combined firing hours for all three turbines

[b]based upon the maximum heat input rate of 2,003 MM BTU/hr for each CTG

[c]based upon the maximum combined heat input rate of 2,125 MM BTU/hr for each CTG/HRSG power train

[d]based upon the worst case PM_{10} emission rate of 12 lb/hr at the maximum combined heat input rate of 2,125 MM BTU/hr

Existing Gas Turbines and Waste Heat Boilers

The proposed annual emission limitations are based upon the following reduced operating scenario for the existing turbines and waste heat boilers. It is expected that the total gas usage for the waste heat boilers will be minimal, as has been the case historically. In any case, the annual heat input rate limits and annual emission limitations that will be imposed as permit conditions will apply to all three existing turbines and all three waste heat boilers combined.

Gas Turbine #1 (262 MM BTU/hr) and Gas Turbine #2 (292 MM BTU/hr):

full load operation - 12 hr/day, 5 day/week, 52 weeks/year
(3,120 hr/yr-turbine)

Gas Turbine #3 (330 MM BTU/hr):

full load operation - 12 hr/day, 5 day/week, 5 months/year
(1,300 hr/yr-turbine)

The corresponding total natural gas usage is calculated as follows:

(3,120 hr/yr)(262 MM BTU/hr + 292 MM BTU/hr) + (1,300 hr/yr)(330 MM BTU/hr)
= 2,157,480 MM BTU/yr

The applicant has based the proposed annual mass emission limits on an annual combined heat input rate of 2,060,652 MM BTU/year.

The proposed regulated air pollutant emission rates corresponding to the reduced operation of the existing turbines and waste heat boilers are summarized in **Table B-6**.

Table B-6
Proposed Annual Regulated Air Pollutant Emissions for Existing Gas Turbines and Waste Heat Boilers

Pollutant	Emission Factor (lb/MM BTU)	Reduced Baseline Gas Usage (MM BTU/yr)	Annual Emissions (ton/yr)	Annual Emission Limits (ton/yr)
NO_x (as NO_2)	0.0181[a]		18.65	18.5
CO	0.11[b]		113.33	113.3
POC (as CH_4)	0.0046[c]	2,060,652	4.74	4.7
PM_{10}	0.0069[c]		7.11	7.1
SO_2	0.0006[b]		0.618	0.6

[a]corresponds to exhaust gas emission concentration of 5.0 ppmvd NO_x @ 15% O_2

[b]AP-42 emission factors; Table 3.3-1, "Emission Factors for Large Uncontrolled Gas Turbines"

[c]derived from results of source testing conducted on July 21, 1999

B-4.0 Cooling Tower Emissions

The cooling tower is exempt from District permit requirements pursuant to Regulation 2-1-128.4. It is conservatively assumed that all particulate matter will be emitted as PM_{10}.

Cooling tower circulation rate:	205,300 gpm
Evaporation Rate:	3,704 gpm
maximum total dissolved solids:	5223 ppm
Drift Rate:	0.0006 %

Water mass flow rate:

(205,300 gal/min)(60 min/hr)(8.34 lb/gal) = 102,732,120 lb/hr

Cooling Tower Drift:

(102,732,120 lb/hr)(0.000006) = 616.4 lb/hr

PM_{10} = (5223 ppm)(616.4 lb/hr)/(10^6)
= 3.22 lb/hr
= 77.3 lb/day (24 hr/day operation)
= 28,198.4 lb/yr (8,760 operating hours per year)
= **14.1 ton/yr**

B-5.0 Auxiliary Boiler Emissions

The maximum hourly, daily, and annual regulated air pollutant emissions for the S-7 Auxiliary Boiler #1 are summarized in **Table B-7**.

Table B-7 Maximum Regulated Air Pollutant Emissions for S-7 Auxiliary Boiler #1

	NO_2	CO	POC	PM_{10}	SO_2
lb/hr[b]	2.76	9.34	0.54	2	0.18
lb/day[c]	66.4	224.3	12.9	48	4.3
lb/yr[d]	3,765.6	12,726.5	1,174.1[e]	5,181.7	244
ton/yr	1.88	6.36	0.59	2.59	0.12

[a]NO_2 emission factor is based upon BACT specification of 9 ppmv NO_x, dry @ 3% O_2. CO emission factor is based upon BACT specification of 50 ppmv, dry @ 3 % O_2. POC, and SO_2 emission factors are from AP-42, Section 1.4, Natural Gas Combustion, Table 1.4-2. PM_{10} emission factor is from AP-42, Table 1.4-1.

[b]Based upon maximum heat input of 256 MM BTU/hr

[c]Based upon 24 hour per day operation @ 256 MM BTU/hr or 6,144 MM BTU/day

[d]Based upon worst-case operating profile of 540 hrs/yr at 100% load and 8,220 hr/yr at 10% load

[e]calculated as follows:

POC = (540 hr/yr)(256 MM BTU/hr)(0.0021 lb/MM BTU) +
(8,220 hr/yr)(25.6 MM BTU/hr)(0.0042 lb/MM BTU)
= 1,174.1 lb/yr

The maximum hourly, daily, and annual regulated air pollutant emissions for the S-8 Auxiliary Boiler #2 are summarized in **Table B-8**.

Table B-8 Maximum Regulated Air Pollutant Emissions for S-8 Auxiliary Boiler #2

	NO_2	CO	POC	PM_{10}	SO_2
lb/hr[b]	2.76	9.34	0.54	2	0.18
lb/day[c]	66.4	224.3	12.9	48	4.3
lb/yr[d]	2,521.5	8,521.7	959[e]	4,432.9	163.4
ton/yr	1.26	4.26	0.48	2.216	0.08

[a]NO_2 emission factor is based upon BACT specification of 9 ppmv NO_x, dry @ 3% O_2. CO emission factor is based upon BACT specification of 50 ppmv, dry @ 3 % O_2. POC, and SO_2 emission factors are from AP-42, Section 1.4, Natural Gas Combustion, Table 1.4-2. PM_{10} emission factor is from AP-42, Table 1.4-1.

[b]Based upon maximum heat input of 256 MM BTU/hr

[c]Based upon 24 hour per day operation @ 256 MM BTU/hr or 6,144 MM BTU/day

[d]Based upon worst-case operating profile of 40 hrs/yr at 100% load and 8,720 hr/yr at 10% load

[e]calculated as follows:

POC = (40 hr/yr)(256 MM BTU/hr)(0.0021 lb/MM BTU) +
(8,720 hr/yr)(25.6 MM BTU/hr)(0.0042 lb/MM BTU)
= 959 lb/yr

B-6.0 Maximum Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1, S-3, & S-5 CTGs and S-2, S-4, and S-6 HRSGs are summarized in **Table B-9**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 17,727,252 MM BTU per year (17,249 MM scf/yr based upon a fuel HHV of 1027.7 BTU/scf) for each gas turbine/HRSG pair. The derivation of the emission factors is detailed in Appendix A.

Table B-9
Worst-Case TAC Emissions for Gas Turbines and HRSGs

Toxic Air Contaminant	Emission Factor (lb/MM scf)	lb/yr[a]	g/sec
Acetaldehyde[c]	6.86E-02	1,183	1.70E-02
Acrolein	2.37E-02	408.8	5.88E-03
Ammonia[b]	12.2	237,155	3.41E00
Benzene[c]	1.36E-02	234.6	3.37E-03
1,3-Butadiene[c]	1.27E-04	2.2	3.15E-05
Ethylbenzene	1.79E-02	308.7	4.44E-03
Formaldehyde[c]	1.10E-01	1,897	2.73E-02
Hexane	2.59E-01	4,467	6.42E-02
Naphthalene	1.66E-03	28.6	4.12E-04
PAHs[c]	2.32E-03	40	5.75E-04
Propylene	7.70E-01	13,282	1.91E-01
Propylene Oxide[c]	4.78E-02	825	1.19E-02
Toluene	7.10E-02	1,225	1.76E-02
Xylene	2.61E-02	450	6.47E-03

[a]from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4, and S-5 & S-6)

[b]based upon the worst-case ammonia slip from the SCR system of 10 ppmvd @ 15% O_2

[c]carcinogenic compounds

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-7 and S-8 Auxiliary Boilers are summarized in **Table B-10**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 588,920 MM BTU per year (573 MM scf/yr based upon a fuel HHV of 1027.7 BTU/scf) for each auxiliary boiler. The derivation of the emission factors is detailed in Appendix A.

Table B-10
Worst-Case TAC Emissions for Auxiliary Boilers

Toxic Air Contaminant	Emission Factor (lb/MM scf)	lb/yr[a]	G/sec
Acetaldehyde[c]	8.9E-03	5.1	7.33E-05
Acrolein	8.00E-04	0.5	6.59E-06
Ammonia[b]	4.4	1,602	0.80
Benzene[c]	4.31E-03	2.5	3.55E-05
Ethylbenzene	2.00E-03	1.1	1.65E-05
Formaldehyde[c]	2.21E-01	127	1.82E-03
Hexane	1.30E-03	0.8	1.07E-05
Naphthalene	3.00E-04	0.2	2.47E-06
PAHs[c]	4.00E-04	0.23	3.30E-06
Propylene	1.55E-01	89	1.28E-03
Toluene	7.80E-03	4.5	6.43E-05
Xylene	5.80E-03	3.3	4.78E-05

[a]emissions from each auxiliary boiler (S-7 and S-8)

[b]based upon the worst-case ammonia slip from the SCR system of 10 ppmvd @ 3% O_2

[c]carcinogenic compounds

The projected toxic air contaminant emissions from the exempt 14-cell cooling tower are summarized in **Table B-11**. The emissions are based upon an water circulation rate of 102,732,120 lb/hr and 8,760 hours of operation per year.

Table B-11
Worst-Case TAC Emissions for Cooling Towers[a]

Toxic Air Contaminant	Emission Factor (lb/hr)	Emission Rate (lb/yr)	Risk Screening Trigger Level (lb/yr)
Ammonia	1.78	15,592	19,300
Arsenic[c]	1.52E-04	**1.33**	**0.024**
Cadmium[c]	1.80E-04	**1.58**	**0.046**
Trivalent chromium[c]	2.74E-04	2.4	N/S
Copper	5.33E-04	4.67	463
Lead[c]	3.33E-04	2.92	29
Mercury	1.42E-04	1.24	57.9
Nickel	7.81E-07	0.007	0.73
Silver	2.33E-04	2.04	N/S
Zinc	3.03E-05	0.05	6,760

[a]based upon 24 hr/day, 365 day/yr operation of 14-cell cooling tower at maximum flow rate

[b]none specified

[c]carcinogenic compound

B-7.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-12**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-12 Maximum Annual Facility Regulated Air Pollutant Emissions (ton/yr)

Source	NO_2	CO	POC	PM_{10}	SO_2
S-1 CTG and S-2 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-3 CTG and S-4 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-5 CTG and S-6 HRSG[a]	92.176	368.48	24.533	45.255	6.14
S-7 Auxiliary Boiler	1.88	6.36	0.59	2.59	0.12
S-8 Auxiliary Boiler	1.26	4.26	0.48	2.216	0.08
Total Permitted Emissions[b]	**279.67**	**1,116.06**	**74.67**	**140.57**	**18.62**
Cooling Towers[c]	0	0	0	14.1	0
Total Facility Emissions	**279.67**	**1,116.06**	**74.67**	**154.67**	**18.62**

[a]includes CTG start-up emissions

[b]new sources only; does not include existing turbines and waste heat boiler emissions

[c]Exempt from BAAQMD permit requirements per Regulation 2-1-128.4.

Table B-13 Maximum Hourly and Daily Baseload Regulated Air Pollutant Emission Rates
(Excluding Gas Turbine Start-up Emissions)

	NO_2	CO	POC	PM_{10}	SO_2
S-1, S-3, and S-5 CTGs[a]					
lb/hr-source	18.1	44.06	5.03	10	1.4
lb/day-source	434.4	1,057.4	120.66	240	33.6
S-1 & S-2, S-3 & S-4, and S-5 & S-6 CTG/HRSG Power Train[b]					
lb/hr-power train	19.21	46.75	5.33	12	1.5
lb/day-power train	461	1,122	128	288	35.7
S-7 & S-8 Auxiliary Boilers					
lb/hr-boiler	2.76	9.34	0.53	2	0.18
lb/day-boiler	66.35	224	12.72	48	4.3

[a]based upon maximum heat input rate of 2002.7 MM BTU/hr for each CTG

[b]Based upon a maximum combined heat input rate for each CTG/HRSG power train of 2,125 MM BTU/hr and 24 hr/day operation and maximum duct burner firing and steam injection power augmentation of 16 hours per day

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-14**.

Table B-14
Maximum Daily Regulated Air Pollutant Emissions By Source (lb/day)

Source	NO_2[c]	CO	POC	PM_{10}	SO_2
S-1 CTG & S-2 HRSG[a]	699.8	4,340.3	169.44	280.2	35
S-3 CTG & S-4 HRSG	699.8	4,340.3	169.44	280.2	35
S-5 CTG & S-6 HRSG	699.8	4,340.3	169.44	280.2	35
S-7 Auxiliary Boiler[b]	66.35	224	12.72	48	4.3
S-8 Auxiliary Boiler[b]	66.35	224	12.72	48	4.3

[a]based upon one 1-hour hot start-up, one 3-hour cold start-up, 16 hours of full load operation with duct burner firing @ 2,125 MM BTU/hr with steam injection power augmentation, and 4 hours of full load operation without duct burner firing at 2003 MM BTU/hr. For example, CO emissions are calculated as follows:

(902 lb/hr)(1 hr/hot SU) + (838 lb/hr)(3 hr/cold SU) + (2,125 MM BTU/hr)(0.022 lb CO/MM BTU)(16 hr/day) + (2,003 MM BTU/hr)(0.022 lb CO/MM BTU)(4 hr/day) = 4,340.3 lb CO/day

[b]based upon 24 hour/day operation of each Auxiliary Boiler at its maximum rated heat input of 256 MM BTU/hr

Table B-15 summarizes the worst-case daily regulated air pollutant emissions from the proposed sources for the purposes of permit condition limitations.

Table B-15 Worst-Case Daily Regulated Air Pollutant Emissions from New Sources (lb/day)

Source (Operating Mode)	NO_2	CO	POC	PM_{10}	SO_2
S-1 CTG (Cold Start-up)	240	2,514	48	36	4.2
S-1 CTG & S-2 HRSG (Full load w/Duct Burner Firing and steam injection power augmentation[a])	307.4	748	85.34	192.1	23.8
S-1 CTG (Full load w/o Duct Burner Firing[b])	72.4	176.3	20.1	40	5.6
S-1 CTG (Hot Start-up)	80	902	16	12	1.4
S-3 CTG (Cold Start-up[c])	240	2,514	48	36	4.2
S-3 CTG & S-4 HRSG (Full load w/Duct Burner Firing and steam injection power augmentation[a])	307.4	748	85.34	192.1	23.8
S-3 CTG (Full load w/o Duct Burner Firing[d])	36.2	88.1	10.05	20	2.8
S-3 CTG (Hot Start-up)	80	902	16	12	1.4
S-5 CTG (Cold Start-up[e])	240	2,514	48	36	4.2
S-5 CTG & S-6 HRSG (Full load w/Duct Burner Firing and steam injection power augmentation[a])	307.4	748	85.34	192.1	23.8
S-5 CTG (Full load w/o Duct Burner Firing[f])	0	0	0	0	0
S-5 CTG (Hot Start-up)	80	902	16	12	1.4
S-7 Auxiliary Boiler[g]	66.35	224	12.72	48	4.3
S-8 Auxiliary Boiler[g]	66.35	224	12.72	48	4.3
Total	**2,123.5**	**13,204.4**	**503.61**	**876.3**	**105.2**

[a]based upon 16 hours of operation at maximum combined heat input of 2,125 MM BTU/hr

[b]based upon 4 hours of operation at maximum heat input of 2,003 MM BTU/hr

[c]occurs at beginning of third hour

[d]based upon 2 hours of operation at maximum heat input of 2,003 MM BTU/hr

[e]occurs at beginning of fifth hour

[f]assuming 0 hours of operation at full load without duct burner firing

[g]based upon 24 hour operation at maximum rated heat input of 256 MM BTU/hr

B-8.0 Modeling Emission Rates

The NO_2 emission rates shown in **Table B-16** were used to model the air quality impacts of the DEC to determine compliance with State and Federal annual ambient air quality standards for NO_2. A screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics revealed that the worst-case annual average impacts for NO_2 occur under the following equipment operating scenario. To meet CEC requirements, the impact analysis included the NO_2 emissions from the exempt natural-gas fired emergency generator and fire pump diesel engine.

Table B-16
NO_2 Emission Rates for Worst-Case Annual-Average Impacts

Source (Operating Mode)	NO_2 lb/yr	NO_2 lb/hr	NO_2 g/s
Gas Turbine (260 hot start-ups/turbine)	20,800		
Gas Turbine (52 cold start-ups/turbine)	12,480		
Gas Turbine (6,844 firing hours/turbine @ 2,003 MM BTU/hr)	123,925		
Gas Turbine and associated HRSG (1,500 hours/turbine w/duct burner firing @ 2,125 MM BTU/hr)	28,815		
S-1 CTG & S-2 HRSG Total Emissions	186,020	21.23	2.675
S-3 CTG & S-4 HRSG Total Emissions	186,020	21.23	2.675
S-5 CTG & S-6 HRSG Total Emissions	186,020	21.23	2.675
S-7 Auxiliary Boiler (540 hours @ 256 MM BTU/hr)	1,493		
S-7 Auxiliary Boiler (8,220 hours @ 25.6 MM BTU/hr)	2,272.7		
S-7 Total Emissions	3,765.7	0.43	0.0542
S-8 Auxiliary Boiler (40 hours @ 256 MM BTU/hr)	110.6		
S-8 Auxiliary Boiler (8,720 hours @ 25.6 MM BTU/hr)	2,411		
S-8 Total Emissions	2,521.6	0.29	0.0365
Emergency Generator (200 firing hours/year)	980	0.11	0.0141
Fire Pump Diesel Engine (200 firing hours/year)	780	0.09	0.0112

The PM_{10} and SO_2 emission rates shown in **Table B-17** were used to model the corresponding air quality impacts to determine compliance with the State and Federal annual ambient air quality standards for PM_{10} and SO_2. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case annual average impacts for PM_{10} and SO_2 occur under the equipment operating scenario shown below.

Table B-17
PM_{10}, and SO_2 Emission Rates for Worst-Case Annual-Average Impacts

Source (Operating Mode)	PM_{10}			SO_2		
	lb/yr	lb/hr	g/s	lb/yr	lb/hr	g/s
S-1 CTG (7,260 hours @ 100% load)	72,709			10,179		
S-1 CTG & S-2 HRSG (1,500 hours w/duct burner firing @ 2,125 MM BTU/hr)	18,009.4			2,231		
S-1 & S-2 Total Emissions	90,718.4	10.35	1.304	12,410	1.42	0.179
S-3 CTG (7,260 hours @ 100% load)	72,709			10,179		
S-3 CTG & S-4 HRSG (1,500 hours w/duct burner firing @ 2,125 MM BTU/hr)	18,009.4			2,231		
S-3 & S-4 Total Emissions	90,718.4	10.35	1.304	12,410	1.42	0.179
S-5 CTG (7,260 hours @ 100% load)	72,709			10,179		
S-5 CTG & S-6 HRSG (1,500 hours w/duct burner firing @ 2,125 MM BTU/hr)	18,009.4			2,231		
S-5 & S-6 Total Emissions	90,718.4	10.35	1.304	12,410	1.42	0.179
S-7 Auxiliary Boiler (540 hours @ 256 MM BTU/hr)	1,078.3			96.8		
S-7 Auxiliary Boiler (8,220 hours @ 25.6 MM BTU/hr)	4,103.4			147.3		
S-7 Total Emissions	5,181.7	0.59	0.074	244.1	0.028	3.53E-03
S-8 Auxiliary Boiler (40 hours @ 256 MM BTU/hr)	79.9			7.2		
S-8 Auxiliary Boiler (8,720 hours @ 25.6 MM BTU/hr)	4,353			156.3		
S-8 Total Emissions	4,433	0.51	0.064	163.5	0.019	2.39E-03
Emergency Generator (200 firing hours/year)	224	0.025	3.2E-03	2.8	3.2E-04	4.03E-05
Fire Pump Diesel Engine (200 firing hours/year)	34	0.004	0.0005	21.2	2.42E-03	3.05E-04
14-Cell Cooling Tower	28,181	3.217	0.405	0	0	0

The PM_{10} and SO_2 emission rates shown in **Table B-18** were used to model the corresponding air quality impacts to determine compliance with the state and federal 24-hour ambient air quality standards for PM_{10} and SO_2. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case impacts for PM_{10} and SO_2 over a 24-hour averaging period occur under the equipment operating scenario shown below.

Table B-18
PM_{10} and SO_2 Emission Rates for Worst-Case 24-hour Average Impacts

Source	PM_{10}			SO_2		
(Operating Mode)	lb/day	lb/hr	g/s	lb/day	lb/hr	g/s
S-1 CTG & S-2 HRSG (Baseload Operation[a])	288	12	1.51	35.7	1.49	0.188
S-3 CTG & S-4 HRSG (Baseload Operation[a])	288	12	1.51	35.7	1.49	0.188
S-5 CTG (70 % Load Operation[b])	165.6	6.9	0.87	20.64	0.86	0.11
S-7 Auxiliary Boiler (100% Load[c])	48	2	0.252	4.3	0.18	0.0227
S-8 Auxiliary Boiler (100% Load[c])	48	2	0.252	4.3	0.18	0.0227
Emergency Generator[d]	1.12	0.0467	5.88E-03	0	0	0
Fire Pump Diesel Engine[d]	0	0	0	0.106	4.42E-03	5.56E-04
14-Cell Cooling Tower	77.21	3.217	0.405	0	0	0

[a]based upon 24 hours of operation at maximum combined heat input of 2,125 MM BTU/hr

[b]based upon 24 hours of operation at 70% load; emission rates per Westinghouse

[c]based upon 24 hour operation at maximum rated heat input of 256 MM BTU/hr

[d]based upon 1 hour of full-load operation per 24-hr period; fire pump and generator not in simultaneous operation

The carbon monoxide emission rates shown in **Table B-19** were used to model the corresponding air quality impacts to determine compliance with the State and Federal 8-hour ambient air quality standards for CO. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case impacts for CO over an 8-hour averaging period occur under the equipment operating scenario shown below.

Table B-19
CO Emission Rates for Worst-Case 8-hour Average Impacts

Source (Operating Mode)	CO		
	lb	lb/hr	g/s
S-1 CTG (Cold Start-up)	2,514		
S-1 CTG & S-2 HRSG (Full Load Operation w/Duct Burner Firing[a])	233.75	343.5	43.28
S-3 CTG (Cold Start-up[b])	2,514		
S-3 CTG & S-4 HRSG (Full Load Operation w/Duct Burner Firing[c])	187	337.6	42.54
S-5 CTG (Cold Start-up[d])	2,514		
S-5 CTG & S-6 HRSG (Full Load Operation w/Duct Burner Firing[e])	140.25	331.8	41.8
S-7 Auxiliary Boiler (100% Load[f])	74.75	9.34	1.177
S-8 Auxiliary Boiler (100% Load[f])	74.75	9.34	1.177
Emergency Generator (1 hr of full-load operation per 8-hr period)	13.3	1.66	0.21
Fire Pump Diesel Engine (not in operation)	0	0	0

[a]based upon 5 hours of operation @ 30^{o}F and maximum combined heat input of 2,125 MM BTU/hr

[b]occurs at beginning of second hour of 8-hour period

[c]based upon 4 hours of operation @ 30^{o}F and maximum combined heat input of 2,125 MM BTU/hr

[d]occurs at beginning of third hour of 8-hour period

[e]based upon 3 hours of operation @ 30^{o}F and maximum combined heat input of 2,125 MM BTU/hr

[f]based upon 8-hour operation at maximum heat input rate of 266 MM BTU/hr

The NO_2, CO, and SO_2 emission rates shown in Table **B-20** were used to model the corresponding air quality impacts to determine compliance with the State and Federal 1-hour ambient air quality standards for NO_2, CO, and SO_2. Based upon a screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics, it was determined that the worst-case impacts for CO and NO_2 over a 1-hour period occur when all three turbines are operating at full load with duct burner firing at an ambient temperature of 90°F and both auxiliary boilers are operating at 100% load.

Table B-20
NO_2, CO, and SO_2 Emission Rates for Worst-Case 1-hour Average Impacts

Source (Operating Mode)	NO_2		CO		SO_2	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
S-1 CTG & S-2 HRSG (Full Load Operation w/Duct Burner Firing[a])	19.2	2.42	46.75	5.9	1.5	0.19
S-3 CTG & S-4 HRSG (Full Load Operation w/Duct Burner Firing[a])	19.2	2.42	46.75	5.9	1.5	0.19
S-5 CTG & S-6 HRSG (Full Load Operation w/Duct Burner Firing[a])	19.2	2.42	46.75	5.9	1.5	0.19
S-7 Auxiliary Boiler (100% Load[b])	2.76	0.347	9.34	1.177	0.18	0.0227
S-8 Auxiliary Boiler (100% Load[b])	2.76	0.347	9.34	1.177	0.18	0.0227
Emergency Generator	4.90	0.617	13.3	1.676	0	0
Fire Pump Diesel Engine	0	0	0	0	0.106	0.0134

[a]based upon maximum combined heat input of 2,125 MM BTU/hr

[b]based upon full load operation at maximum heat input rate of 256 MM BTU/hr

B-9.0 Maximum Facility Emissions During Commissioning Period

Table B-21 summarizes the worst-case 1-hour and 8-hour emission rates for the DEC during the commissioning period, when the SCR systems will not be installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the DEC would contribute to an exceedance of the 1-hour State NO_2 ambient air quality standard, the 1-hour State and Federal CO standards, and the 8-hour State and Federal CO standards during the commissioning of the gas turbines, HRSGs, and related equipment. It is assumed that only one gas turbine will be commissioned at one time.

Table B-21
Worst-Case Short-Term NO_2 and CO Emissions from CTGs during Commissioning Period

	NO_2		CO	
1-hour Emission Rates	lb/hr	g/s	lb/hr	g/s
S-1 CTG	362[a]	45.61	902[b]	113.7
S-3 CTG	362[a]	45.61	902[b]	113.7
S-5 CTG	362[a]	45.61	902[b]	113.7
8-hour Emission Rates[c]				
S-1 CTG & S-2 HRSG	N/A	N/A	343.5	43.28
S-3 CTG & S-4 HRSG	N/A	N/A	343.5	43.28
S-5 CTG & S-6 HRSG	N/A	N/A	343.5	43.28

[a]based upon a conservative exhaust gas NO_x emission concentration of 50 ppmvd @ 15% O_2 for each turbine when operating without abatement by the SCR system; twice the turbine vendor unabated guaranteed emission rate of 25 ppmvd @ 15 % O_2

[b]equal to the turbine hot start-up CO hourly emission rate

[c]based upon one 3-hour cold start-up, followed by 5 hours of 100% load operation of CTG and HRSG at the maximum combined heat input rate of 2,125 MM BTU/hr; see Table B-17 for further detail

Appendix C

Emission Offsets

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required only for permitted sources. Therefore, emission offsets will be required for the POC, NO_x, and PM_{10} emission increases associated with S-1 CTG, S-2 HRSG, S-3 CTG, S-4 HRSG, S-5 CTG, S-6 HRSG, S-7 Auxiliary Boiler #1, and S-8 Auxiliary Boiler #2 only. Pursuant to District Regulations, emission offsets are not required for the PM_{10} emissions attributed to the exempt cooling towers and the NO_x, POC, and PM_{10} emissions attributed to the exempt emergency generator and exempt fire pump diesel engine.

Table C-1 Emission Offset Summary

	NO_x	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	279.67	1,116.06	74.67	140.57	18.62
Proposed New Source Annual Emission Limits[b] (ton/yr)	279.6	1,116.1	74.4	140.7	16.2
Contemporaneous Emission Reductions[c] (ton/yr)	77.71	212.3	8.92	13.325	1.2
Net Annual Emission Increases (ton/yr)	201.89	903.8	65.48	127.375	15
Offset Requirement Triggered	Yes	N/A	Yes	Yes	N/A
Offset Ratio	1.15:1.0[d]	N/A	1.15:1.0[d]	1.0:1.0	N/A
Offsets Required (tons)	**232.17**	**0**	**75.3**	**127.37**	**0**

[a]sum of Gas Turbine (S-1, S-3, & S-5), HRSG (S-2, S-4, & S-6), and Auxiliary Boiler (S-7 & S-8) emission increases

[b]permit condition annual emission limitations as calculated by applicant

[c]resulting from the reduced operation of S-67, S-70, & S-73 Gas Turbines and S-68, S-71, & S-74 Waste Heat Boilers

[d]Pursuant to District Regulation 2-2-302, the applicant must provide emission offsets at a ratio of 1.15 to 1.0 since the proposed facility NO_x and POC emissions from permitted sources will each exceed 50 tons per year

Contemporaneous Emission Reduction Credits

Pursuant to District Regulations 2-2-214 and 2-2-242, the Delta Energy Center will provide contemporaneous emission reduction credits (ERCs) to offset a portion of the proposed NO_x, POC, and PM_{10} emission increases for the facility. These contemporaneous ERCs will result from the reduced operation of the existing permitted turbines and waste heat boilers currently in operation at the Calpine Pittsburg, Inc. facility.

Pursuant to Regulation 2-4-301.1, these emission reductions are bankable, since they result from the installation of a level of control greater than required by regulation. The existing turbines and waste heat boilers currently achieve an average exhaust gas NO_x emission concentration of approximately 4.5 ppmvd @ 15% O_2 through the installation and operation of SCR systems. District Regulation 9, Rule 9, limits NO_x emissions to 9 ppmvd @ 15% O_2 for turbines equipped with SCR.

The limitations on deposits as given in Regulation 2-4-303 do not apply to the proposed emission reduction credits.

The proposed emission reduction credits meet the definition of ERC as given in Regulation 2-2-201 since they exceed the emission reductions achieved through the use of current Reasonably Available Control Technology. As stated earlier, the gas turbines currently achieve an average exhaust gas NO_x emission concentration of approximately 4.5 ppmvd @ 15% O_2. Current RACT is defined by District Regulation 9, Rule 9, section 301.3 to be 9 ppmvd NO_x @ 15% O_2 for turbines equipped with SCR.

Furthermore, the emission reductions are real, permanent, quantifiable, and enforceable. The NO_x, emission reductions are real and quantifiable since they are based upon the use of SCR and CEM data and the PM_{10} and POC emission reductions are real and quantifiable since they are based upon reduced fuel usage rates and source test data. The emission reductions will be permanent and enforceable through the imposition of permit conditions that will require the use of the SCR systems at all times, limit annual natural gas usage, and limit annual mass regulated pollutant emissions.

The baseline NO_x, POC, and PM_{10} emissions for the existing turbines will be determined pursuant to District regulation 2-2-605.2 and will be based upon the actual annual emissions from the sources, averaged over the highest twelve consecutive month period occurring during the last five years immediately preceding the application and which was representative of normal operation.

The applicant has designated the twelve month period from June 1996 through May 1997 as the baseline period. Based upon natural gas usage records for the sources in question, the total usage for all three gas turbines during the designated period was 5,920,420 MM BTU. Based upon a review of the natural gas usage records submitted by the applicant, this annual usage is found to be representative of normal operation as shown in Table C-2 below.

Although each gas turbine/waste heat boiler power train exhausts through a common stack, the contribution of the waste heat boilers to total combustion product emissions is ignored since the waste heat boiler gas usage is negligible when compared to the turbine gas usage. Accordingly, the emission reduction credits calculation is based upon turbine gas usage only. As shown in **Table C-2**, the total waste heat boiler usage is a small fraction of the total facility gas usage.

Table C-2 Annual Natural Gas Usage for Existing Gas Turbines and Waste Heat Boilers

Consecutive Twelve-Month Period	Turbine Gas Usage (MM BTU/ consecutive 12-month period)	Waste Heat Boiler Gas Usage (MM BTU/ consecutive 12-month period)
Calendar Year 1993	6,070,816	33,520
CY 1994	5,403,680	N/A
CY 1995	5,504,915	24,237
CY 1996	5,670,475	26,107
CY 1997	5,790,656	105,072
June 96' – May 97'	5,920,420	43,733

Table C-3 Baseline Emissions for Existing Gas Turbines

Pollutant	Emission Factor (lb/MM BTU)	Baseline Gas Usage (MM BTU/yr)	Baseline Emissions lb/yr	Baseline Emissions ton/yr
NO_x (as NO_2)	0.0325[a]	5,920,420	192,414	96.21
PM_{10}	0.0069[b]		40,850.9	20.425
POC (as CH_4)	0.0046[b]		27,233.9	13.62
CO	0.11[c]		651,246	325.6
SO_2	0.0006[d]		3,552.2	1.8

[a]based upon current RACT-level emission limitation of 9 ppmvd @ 15% O_2 pursuant to District Regulation 9-9-301.3, "Nitrogen Oxides from Stationary Gas Turbines"

[b]derived from results of source testing conducted on July 21, 1999

[c]AP-42 Table 3.3-1, "Emission Factors for Large Uncontrolled Gas Turbines"; Factor Rating D

[d]AP-42 Table 3.3-1, "Emission Factors for Large Uncontrolled Gas Turbines"; Factor Rating B

NO_x Emission Factor Derivation

The combined baseline NO_x emissions from each gas turbine/waste heat boiler pair is based upon a RACT-level exhaust gas emission concentration of 9 ppmv, dry @ 15% O_2.

This concentration is converted to a mass emission factor as follows:

(9 ppmvd)(20.95 - 0)/(20.95 - 15) = 31.69 ppmv NO_x, dry @ 0% O_2

($31.69/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lb-mol)(8600 dscf/MM BTU)

= **0.0325 lb NO_2/MM BTU**

The contemporaneous emission reduction credits generated by the existing turbines are summarized in **Table C-4** and based upon the difference between the baseline emissions established above and the new proposed emission limitations that will be imposed as permit conditions.

Table C-4
Contemporaneous Emission Reduction Credits Resulting from Reduced Operation of Existing Gas Turbines

Pollutant	Baseline Emissions (lb/yr)	Baseline Emissions (ton/yr)	Proposed Annual Emission Limitations[a] (ton/yr)	Contemporaneous Emission Reductions (ton/yr)
NO_x (as NO_2)	192,414	96.21	18.5	77.71
PM_{10}	40,850.9	20.425	7.1	13.325
POC (as CH_4)	27,233.9	13.62	4.7	8.92

[a]will apply to combined emissions from all three turbines and all three waste heat boilers

Appendix D

Health Risk Assessment

As a result of the combustion of natural gas at the proposed CTGs, HRSGs, and auxiliary boilers and the use of water treatment chemicals in the cooling towers, the proposed Delta Energy Center will emit the toxic air contaminants summarized in Table 2, “Maximum Facility Toxic Air Contaminant (TAC) Emissions”. In accordance with the requirements of CEQA, the BAAQMD Risk Management Policy, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE.

The public health impact of the carcinogenic compound emissions is quantified through the increased carcinogenic risk to the maximally exposed individual (MEI). A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Per the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the acute and chronic hazard indices which is the ratio of the expected concentration of a compound to the acceptable concentration of the compound. When more than one toxic compound is emitted, the hazard indices of the compounds are summed to give the total hazard index. The acute hazard index quantifies the magnitude of the adverse health affects caused by a brief (no more than 24 hours) exposure to a chemical or group of chemicals. The chronic hazard index quantifies the magnitude of the adverse health affects from prolonged exposure to a chemical caused by the accumulation of the chemical in the human body. Per the BAAQMD Risk Management Policy, a project with a total hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

Table D-1 Health Risk Assessment Results

Maximum Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index
0.16	0.04	0.06

In accordance with the BAAQMD Risk Management Policy, the increased carcinogenic risk and acute and chronic hazard indices attributed to this project are each considered to be not significant since they are each less than 1.0. Therefore, the Delta Energy Center project is deemed to be in compliance with the BAAQMD Risk Management Policy.

Appendix E

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE DELTA ENERGY CENTER

August 9, 1999

BACKGROUND

Calpine Corporation and Bechtel Enterprises have submitted a permit application (# 19414) for a proposed nominal 880-MW combined cycle power plant, the Delta Energy Center - UTM coordinates (601.495 E, 4208.121 N). The facility is to be composed of three natural gas-fired turbines , three heat recovery steam generators each equipped with duct burners, two auxiliary boilers, and an emergency generator and fire pump engine. Natural gas will be the only fuel consumed except for the 300 hp Diesel fire pump. The proposed project is a major modification to a major source. The project will result in an increase in air pollutant emissions of NO_2, CO, PM_{10} and SO_2 triggering regulatory requirements for an air quality impact analysis.

AIR QUALITY IMPACT ANALYSIS REQUIREMENTS

Requirements for air quality impact analysis are given in the District's New Source Review (NSR) Rule: Regulation 2, Rule 2.

The criteria pollutant annual worst case emission increases for the Project are listed in Table E-1, along with the corresponding significant emission rates for air quality impact analysis.

Table E-1
Comparison of Proposed Project's Annual Worst-Case Emissions to Significant Emission Rates for Air Quality Impact Analysis

Pollutant	Proposed Project's Emissions (tons/year)	Significant Emission Rate (tons/year) (Reg-2-2-304 and 2-2-305)
NO_x	283.5	40
CO	1152.5	100
PM_{10}	154.9	15
SO_2	16.2	40

Table E-1 indicates that the proposed project emissions exceed the significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), and fine particulate matter (PM_{10}), The detailed requirements for air quality impact analysis for these pollutants are given in Sections 304 and 305 of the District's NSR Rule.

The District's NSR Rule also contains requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in Section 414 of Regulation 2 Rule 2. According to subsection 414.1, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels). If the maximum impact for a particular pollutant is predicted to exceed the significance level for air quality impacts, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_x, CO and PM_{10} were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height), impacts due to building downwash, and impacts due to inversion breakup and shoreline fumigation.

Emissions from the turbines will be exhausted from three 144 foot exhaust stack . Emissions from the auxiliary boiler are exhausted through two 115 foot stacks. The project also includes a cooling tower (comprised of 14 cells) with a release height of 60 feet. Because the facility will be dispatchable, the worst case emission rates varied with each averaging period. Table E-2 contains the emission rates used in each of the modeling scenarios: turbine commissioning, start-up, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of one of the turbines without controls and only occurs during the initial operation of the equipment after installation. Start-up is the beginning of any of the subsequent duty cycles to bring the facility from idle status up to power production. These emission estimates are from Table 8.1-22 of the Application for Certification.

The applicant used the EPA models SCREEN3(version 96043) and ISCST3(version 99155). Four years (1994-1997) of hourly meteorological data from a Pacific Gas and Electric meteorological monitoring station were used in the modeling analysis. This monitoring site is roughly four miles to the west of the project site. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation was evaluated using the SCREEN3 model. Shoreline Fumigation was evaluated using SCREEN3.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table E-3 for the averaging periods for which AAQS and PSD increments have been set. Also shown in Table E-3 are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414, no further analysis is required for the CO and PM_{10} modeled impacts. However, the 1-hour NO_2 modeled impacts are over the significant air quality impact level requiring further analyses.

Table E-2
Averaging Period Emission Rates Used in Modeling Analysis (g/s)

Pollutant Source	Max (1-hour)	Commissioning[1] (1-hour)	Start-up[2] (1-hour)	Maximum (8-hour)	Maximum (24-hour)	Maximum Annual Average
NO_x						
Turbine/DB 1	2.42	45.6	10.1	n/a	n/a	2.675
Turbine/DB 2	2.42					2.675
Turbine/DB 3	2.42					2.675
Boiler 1	0.36					0.0621
Boiler 2	0.36					0.0443
Em Gen	0.62					0.0141
Fire Pump	0					0.0112
CO						
Turbine/DB 1	7.81	114	114	47.5	n/a	n/a
Turbine/DB 2	7.81			46.5		
Turbine/DB 3	7.81			45.5		
Boiler 1	1.17			1.17		
Boiler 2	1.17			1.17		
Em Gen	1.68			0.21		
Fire Pump	0			0		
PM_{10}						
Turbine/DB 1	n/a	n/a	n/a	n/a	1.51	1.30
Turbine/DB 2					1.51	1.30
Turbine/DB 3					0.869	1.30
Boiler 1					0.252	0.0747
Boiler 2					0.252	0.0639
Em Gen					0.0462	0.00316
Fire Pump					0	0.000575

[1] Commissioning is the original start-up of the turbines and only occurs during the initial operation of the equipment after installation. The 1-hour NO_x and CO emissions are based on cold start-up of one turbine with no controls.. [2]Start-up is the beginning of any of the subsequent duty cycles to bring the facility up to power production.

Table E-3
Maximum Predicted Ambient Impacts of Proposed Project ($\mu g/m^3$)
[Overall maximum in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Startup	Maximum Modeled Impact (UTM coordinates of max. impact)	Shoreline Fumigation Impact	Significant Air Quality Impact Level
NO_2[1]	1-hour annual	219 -	48 -	**267** (601.2887, 4208.2666) **0.94** (601.5561, 4208.1708)	46 -	19 1.0
CO	1-hour 8-hour	546 -	546 -	**725** (601.2887, 4208.2666) **244** (601.4951, 4207.8214)	149 -	2000 500
PM_{10}	24-hour annual	- -	- -	**4.95** (601.4351, 4207.7614) **0.27** (602.8751, 4208.0014)	2.7 -	5 1

[1] The one-hour average NO_2 impacts are based on the conservative assumption that all of the plume NO_x is in the form of NO_2. The long term NO_2 impacts are determined using the EPA approved value of 0.75 for the annual average NO_2/NO_x ratio.

Background Air Quality Levels

Regulation 2-2-111 of the NSR rule entitled PSD monitoring exemption, exempts an applicant from the requirement of monitoring background concentrations in the impact area (section 414.3) provided the impacts from the proposed project are less than specified levels. Table E-4 lists the applicable exemption standards and the maximum impacts from the proposed facility. As shown, the modeled impacts are below the preconstruction monitoring threshold.

Table E-4
PSD Monitoring Exemption Levels and Maximum Impacts from the Proposed Project for NO_2 ($\mu g/m^3$)

Pollutant	Averaging Time	Exemption Level	Maximum Impacts from Proposed Project
NO_2	Annual	14	0.94

Three District operated monitoring stations, Pittsburg, Concord, and Bethel Island were chosen as representative of the background NO_2 concentrations. Table E-5 contains the concentrations measured at the three sites for the past 3 years.

Table E-5
Background NO_2 Concentrations ($\mu g/m^3$) at Pittsburg, Concord and Bethel Island Monitoring Sites for the Past Three Years
(maximum in bold print)

Monitor	Highest 1-hour NO_2 concentration
Pittsburg	
1995	150.4
1996	131.6
1997	131.5
Concord	
1995	**169.2**
1996	150.4
1997	150.4
Bethel Island	
1995	112.8
1996	112.8
1997	94.0

Table E-6 contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. National and California ambient NO_2 standards are not exceeded from the proposed project. Therefore, in accordance with subsection 414.1, only a visibility, soils and vegetation impact analysis is further required.

Table E-6
California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed Project ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	169	267	436	470	---

VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using EPA's VISCREEN (version 88341) visibility screening model. The analysis shows that the proposed project will not cause any impairment of visibility at Point Reyes, the nearest Class I area.

Vegetation and soils in the project study area were inventoried. Maximum project NO_2, CO and PM_{10} concentrations will not result in significant soil and/or vegetation impacts.

CONCLUSIONS

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for NO_2, CO and PM_{10}. The applicant's analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.