BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In the matter of Russell City Energy Center	)	PSD Appeal No. 08-01

DECLARATION OF WEYMAN LEE, P.E.

I, Weyman Lee, P.E., hereby declare as follows.

1. I am employed by the Bay Area Air Quality Management District ("District") as an Air Quality Engineer. I was the Air Quality Engineer with responsibility for the District's role in the Russell City Energy Center amendment ("Project") licensing proceeding before the California Energy Commission ("CEC"), CEC Docket No. 01-AFC-7C, and for the issuance of the District Authority to Construct in connection with that proceeding. In addition, I was the Air Quality Engineer with responsibility for the District's issuance of the Prevention of Significant Deterioration ("PSD") permit for the Project. I have personal knowledge of the matters stated herein and know them to be true (or, where indicated, I am informed and believe that they are true), and I can testify truthfully and competently thereto.

2. The District issued a Preliminary Determination of Compliance ("PDOC") and Draft PSD Permit for the Project, which is dated March 27, 2007. A true and correct copy of the PDOC/Draft PSD Permit is attached hereto as Exhibit A. The District issued a Public Notice of the issuance of the PDOC/Draft PSD Permit, dated April 2, 2007, which the District published in the Oakland Tribune, a newspaper of general circulation in Alameda County where the Project is located, on April 12, 2007. Also on April 2, 2007, the District mailed notice of issuance of the PDOC/Draft PSD Permit, along with a copy of the document, to the California Energy

Commission; to Region 9 of the US Environmental Protection Agency; to the four local air quality regulatory agencies for the jurisdictions that border the District's jurisdiction (Sacramento Metropolitan, San Joaquin Valley, Yolo-Solano, and Monterey Bay); to the Point Reyes National Seashore; and to the Project applicant. The letter to the California Energy Commission also caused a copy of the PDOC/PSD Permit to be mailed to each of the interested parties on the Energy Commission's service list for the Project, I am informed and believe, as it is the practice of the staff of the Commission to mail copies of all written materials that are filed in a particular proceeding to all persons included on the service list for the proceeding.

3. The publication of the notice of the issuance of the PDOC/Draft PSD Permit as described in the preceding paragraph solicited comments from interested parties on the PDOC/Draft PSD Permit and commenced a 30-day public comment period, to be open until May 12, 2007. The notice of issuance indicated, among other things, that the public comment period was being provided pursuant to District Regulation 2-2-405.

4. The District received only one comment, from the Project Applicant Calpine Corporation. The comment was in the form of a marked-up copy of the PDOC/Draft PSD Permit making a few minor changes to the wording of certain permit conditions. The District did not receive any other comments.

5. The District did receive a letter from the Staff of the California Energy Commission addressing certain points in the PDOC/Draft PSD Permit, but it was dated May 29, 2007, and therefore was not a comment for purposes of the public comment period that the District was obligated to consider. The District nevertheless did consider the points raised in the letter, and responded to the points as addressed below.

6. The District then issued a Final Determination of Compliance ("FDOC") for the Project, dated June 19, 2007. On June 27, 2007, the District mailed copies of the FDOC to the California Energy Commission; to Region 9 of the US Environmental Protection Agency; to the 4 local air quality regulatory agencies for the jurisdictions that border the District's jurisdiction (Sacramento Metropolitan, San Joaquin Valley, Yolo-Solano, and Monterey Bay); to the Point Reyes National Seashore; and to the Project applicant. The District also sent a letter to the California Energy Commission on June 27, 2007, responding to the points raised in the Commission's letter of May 29, 2007. The District pointed out in this letter that the May 29, 2007, letter was not timely to act as a public comment that the District was obligated to consider, but that the District considered it any way and responded.

7. Then, on November 1, 2007, after the California Energy Commission issued its final certification of the Project, the District issued its Authority to Construct ("ATC") and PSD permit for the Project. The document that serves as the ATC and PSD Permit is the FDOC document, Exhibit B hereto. The relevant portions of the permitting analysis in the FDOC serve as the Engineering Evaluation for the ATC and Statement of Basis for the PSD Permit, respectively, and the relevant permit conditions in the FDOC serve as the ATC and PSD Permit conditions, respectively. On November 1, 2007, the District mailed notice of issuance of the ATC and PSD Permit, along with copies of the ATC and PSD Permit, to the California Energy Commission; to Region 9 of the US Environmental Protection Agency; to the four local air quality regulatory agencies for the jurisdictions that border the District's jurisdiction (Sacramento Metropolitan, San Joaquin Valley, Yolo-Solano, and Monterey Bay); to the Point Reyes National Seashore; and to the Project applicant.

8. The District issued the PSD Permit upon authority delegated from EPA Region 9 pursuant to an agreement entitled "EPA – Bay Area Air Quality Management District Agreement for Limited Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21", effective January 20, 2006.

9. The District also issued a public notice of the issuance of the ATC, which was dated November 30, 2007, and was published in the Oakland Tribune on December 6, 2007.

10. I received inquiries about the Project from Mr. Rob Simpson during the month of November, 2007. In response to these inquiries, I faxed him a copy of the ATC/Final PSD Permit on November 29, 2007, at (510) 583-3201, the fax number he gave me.

I declare under penalty of perjury under the laws of California that the foregoing is true and correct, and that this declaration was executed on January 17, 2008.

Weyman Lee, P.E.

Exhibit A

EXHIBIT A

Amended
Preliminary
Determination of Compliance

Russell City Energy Center

Bay Area Air Quality Management District
Application 15487

March 27, 2007

Weyman Lee, P.E.
Air Quality Engineer

Contents

Tables

I Background

This is the amended Preliminary Determination of Compliance (PDOC) for the Russell City Energy Center (RCEC), a 600-MW, natural-gas fired, combined-cycle merchant power plant proposed by Calpine Corporation (Calpine). The project was originally certified by the California Energy Commission in September, 2002. However, the site has been relocated approximately 1,500 feet to the north from the original location (1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay in the City of Hayward). Hence an amendment to the Authority to Construct is required.

The RCEC will consist of two natural gas fired Westinghouse 501F combustion turbine generators (CTGs), one steam turbine generator (STG) and associated equipment, two supplementally fired heat recovery steam generators (HRSGs), a 9-cell wet cooling tower, and a 300 hp diesel fire pump engine.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the Preliminary Determination of Compliance (PDOC) document for the RCED. It will also serve as the evaluation report for the BAAQMD Authority to Construct application number 15487.

The PDOC describes how the proposed RCEC 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. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, this PDOC 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. Because the PDOC documents the preliminary decision of the APCO to issue a PSD permit, it is subject to the public notice requirements of Regulation 2-2-405.

II Project Description

1. Permitted Equipment

Calpine is proposing a combined-cycle combustion turbine power generation facility with a nominal electrical output of 600 MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to a steam turbine generator with a rated electrical output of 235 MW.

The RCEC will consist of the following permitted equipment:

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute, with efficiency drift eliminators, make and model to be determined.

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

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

Base Load: Maximum continuous output with duct firing

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 periods 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

The chart below outlines the maximum operating annual air pollutant emissions for this project. The carbon monoxide emissions have decreased from 584.2 tons/year to 389.3 tons/year and the PM_{10} emissions have increased slightly from 86.4 tons/year to 86.8 tons/year. All other emission rates are unchanged from previous application #2896.

NO_2 (ton/yr)	CO (ton/yr)	POC (ton/yr)	PM_{10} (ton/yr)	SO_2 (ton/yr)
134.6	389.3	28.5	86.8	12.2

3. Air Pollution Control Strategies and Equipment

The proposed RCEC 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 and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT level NO_x emission limit of 2 ppmvd @ 15% O_2 (one hour average).

b. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which operate on a lean fuel mixture that minimizes incomplete combustion and CO emissions. The HRSGs will be equipped with low-NO_x duct burners which are also designed to minimize CO emissions. Furthermore, the gas turbines and HRSGs will be abated by oxidation catalysts which will oxidize the CO emissions to produce CO_2 and water. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 4 ppmvd @ 15% O_2 (three hour average).

c. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with low-NO_x burners, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the turbines and HRSGs will be abated by oxidation catalysts which will also reduce POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 1 ppmvd @ 15% O_2 (one hour average).

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

The gas turbines and HRSG duct burners will burn exclusively PUC-regulated natural gas to minimize SO_2 and PM_{10} emissions. Because the SO_2 emission rate is proportional to the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of "low sulfur content" 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.

Table 1 Summary of Control Strategies and Emission Limitations for Gas Turbines and HRSG Duct Burners

Source	Control Strategy and Emission Limit[a]				
	NOx	**CO**	**POC**	**PM_{10}**	**SO_2**
Gas Turbine & HRSG Power Trains	DLN Combustors/SCR	DLN Combustors/ Oxidation Catalyst	DLN Combustors/ Oxidation Catalyst	PUC-Regulated Natural Gas	PUC-Regulated Natural Gas
	2 ppmv	4 ppmv	2 ppmv	12 lb/hr	2 lb/hr

[a] ppmv concentrations dry at 15% O_2

III 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 2 is a summary of the daily maximum regulated air pollutant emissions for the permitted sources at RCEC. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NPOC, NO_x, SO_2, PM_{10}, or CO are subject to the BACT requirement for that pollutant.

Table 2 Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources (lb/day)

Source	Pollutant (lb/day)				
	Nitrogen Oxides (as NO_2)	Carbon Monoxide	Precursor Organic Compounds	Particulate Matter (PM_{10})	Sulfur Dioxide
S-1 Gas Turbine & S-2 HRSG[a]	776	5387	148	279	37
S-3 Gas Turbine & S-4 HRSG[a]	776	5387	148	279	37
S-5 Cooling Tower[b]				68	
S-6 Fire Pump Diesel Engine[c]	2.82	0.22	0.21	0.079	0.0033

[a] NOx, CO, and POC emission rates are based upon one 360 minute cold start-up and 18 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day; PM_{10} and SO_2 emission rates are based upon 24 hours of Gas Turbine/HRSG baseload operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day

[b] emission rates based upon 24 hr/day operation at maximum emission rates

[c] emission rates based upon 1 hr/day operation at maximum emission rates

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 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-3 SCR Systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Regulation 2, Rule 5.

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Turbines/HRSGs				
Acetaldehyde	2.33E+03	6.4E+01		
Acrolein	3.21E+02	2.3E+00	4.03E-02	4.2E-04
Ammonia	1.21E+05	7.7E+03	1.52E+01	7.1E+00
Benzene	2.26E+02	6.4E+00	2.84E-02	2.9E+00
1,3-Butadiene	2.16E+00	1.1E+00		
Ethylbenzene	3.04E+02	7.7E+04		
Formaldehyde	1.56E+04	3.0E+01	1.96E+00	2.1E-01
Hexane	4.40E+03	2.7E+05		
Naphthalene	2.82E+01	1.1E-02		
Total PAHs	1.80E+00	1.1E-02		
Propylene	1.31E+04	1.2E-02		
Propylene Oxide	8.13E+02	4.9E+01	1.02E-01	6.8E+00
Toluene	1.21E+03	1.2E+01	1.51E-01	8.2E+01

Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Xylenes	4.08E+02	2.7E+04		
Cooling Tower				
Ammonia	1.86E+02	7.7E+03	2.12E-02	7.1E+00
Arsenic	1.55E-01	1.2E-02	1.77E-05	4.2E-04
Cadmium	2.48E-01	4.5E-02		
Hexavalent chromium	1.27E+00	1.3E-03		
Copper	1.88E+00	9.3E+01		
Lead	5.88E-01	5.4E+00	6.71E-05	2.2E-01
Manganese	2.58E+00	7.7E+00		
Mercury	1.86E-03	5.6E-01		
Nickel	1.45E+00	7.3E-01	1.66E-04	1.3E-02
Selenium	2.16E-01	7.7E+02		
Zinc	5.94E+00	1.4E+03		
Firepump Engine				
Diesel Exhaust Particulate	4.0E+00	5.8E-01		

Table 4 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of any of the trigger levels shown must perform modeling to assess the net air quality impact of the proposed facility.

Table 4
Maximum Annual Facility Regulated Air Pollutant Emissions

Pollutant	Permitted Source Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	134.6	100
Carbon Monoxide	389.3	100
Precursor Organic Compounds	28.5	N/A[d]
Particulate Matter (PM_{10})	86.8	100
Sulfur Dioxide	12.2	100

[a] emission increases from proposed gas turbines and heat recovery steam generators, cooling tower and fire pump diesel engine; specified as permit condition limit

[b] includes start-up and shutdown emissions for gas turbines

[c] for a new major facility

[d] there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal 1-hour ambient air quality standard for ozone

The sulfuric acid mist (H_2SO_4) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. The applicant has accepted an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established.

IV Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed Russell City Energy Center 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 RCEC 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 2-2-404, "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 the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

Gas Turbines and HRSGs

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners of the proposed RCEC Project. 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 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for NO_x for a combined cycle gas turbine with a rated output $\geq$ 40 MW as 2.0 ppmvd @ 15% O_2 averaged over one hour, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with dry low-NOx combustors. The EPA has accepted this BACT determination as Federal LAER. This BACT determination has been imposed on recent BAAQMD permits issued for : East Altamont Energy Center (Application #2589), and Pico Power Project (Application #6481). In addition, Palomar Energy Project located in San Diego County, a 546 MW combined cycle power plant, recently started up (4/1/06) with a NO_x emission requirement of 2.0 ppmvd, @ 15% O_2, averaged over one hour.

  A NO_x emission concentration of 2.0 ppmvd, @ 15% O_2, averaged over one hour, has been established as "achieved-in-practice" BACT for NO_x based upon our review of CEM data for the ANP Blackstone power plant, a nominal 550-MW combined cycle facility. The ANP Blackstone power plant is located in Blackstone, Massachusetts and consists of two ABB GT-4 Gas Turbines rated at 180-MW each with unfired heat recovery steam generators. We reviewed CEM data for approximately 2,313 firing hours for unit 1 and 2,737 firing hours for unit 2 which occurred from April 2001 to April 2002. With the exception of start-up and shutdown periods, the NOx concentrations were below the 2.0 ppmvd limit by a sufficient margin to demonstrate consistent, continuous compliance.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.0 ppmvd NO_x @ 15% O_2, averaged over one hour during all operating modes except gas turbine start-ups and shutdowns. This meets the current District BACT 1 determination and meets or exceeds the current EPA and ARB BACT determinations for NO_x. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. The NO_x emissions from the turbine and HRSG will be abated through the use of a selective catalytic reduction (SCR) system with ammonia injection. The NO_x emission concentration will be verified by a CEM (continuous emissions monitor) located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of less than or equal to 2.0 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

The following "top-down" BACT analysis for NO_x has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. Although this analysis is based upon a controlled NOx emission concentration of 2.5 ppmv instead of the applicable NOx emission rate of 2.0 ppmv, the District has determined that the conclusions of the analysis are applicable to this project.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the RCEC Project. Stone & Webster Management Consultants, Inc. of Denver, Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated and because the selected control technology, SCR, has been demonstrated in practice to achieve NOx emission concentrations of less than 2 ppmv, averaged over one hour, we do not consider $SCONO_x$ to be a viable control alternative for NO_x.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 5 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Table 5 Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
$SCONO_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a] based upon uncontrolled NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[b] based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[c] "Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d] does not apply since there is no difference in emission reduction quantity between alternatives

[e] "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 5, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 5, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15% O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.024 and a chronic hazard index of 0.007 resulting from the emission of all non-carcinogenic compounds, including ammonia, from the gas turbines. In accordance with the District Regulation 2, Rule 5 and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The RCEC will utilize aqueous ammonia in a 19% (by weight) solution. Consequently, the RCEC will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed RCEC facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the RCEC does not justify the elimination of SCR as a control alternative.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER specification for NO_x without causing significant energy, economic, or environmental impacts. Thus, neither can be eliminated as a viable control alternative. The only aspect of this analysis affected by the current NOx BACT standard of 2.0 ppmvd @ 15% O_2, averaged over one hour is the cost of compliance. The increased cost of control for each technology is not expected to affect the conclusion of this analysis. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of two distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only 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.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for CO for combined cycle gas turbines with a rated output of ≥ 50 MW as a CO emission concentration of ≤ 4.0 ppmvd @ 15% O_2. This BACT specification is based upon the Sacramento Power Authority (Campbell Soup facility) located in Sacramento County, California. BACT 1 (technologically feasible/cost-effective) is currently not specified. This emission rate limit applies to all operating modes except gas turbine start-up and shutdown.

The applicant has agreed to a CO emission limit of 4.0 ppmvd @ 15% O_2, averaged over any rolling 3-hour period. This satisfies the current BACT 2 limitation as discussed above. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. CO emissions from the turbine and HRSG will be abated through the use of an oxidation catalyst. The CO emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

There currently is no BACT 1 (technologically feasible/cost-effective) specification for POC for this source category. Currently, District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for POC for combined cycle gas turbines with an output rating ≥ 50

MW as 2 ppmv, dry @ 15% O_2, which is typically achieved through the use of dry-low NOx combustors and/or an oxidation catalyst. This is based upon the Delta Energy Center and Metcalf Energy Center, which were recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

The applicant has proposed to not exceed a POC stack concentration of 1 ppmvd @ 15% O_2 with the use of dry-low NOx combustors and/or an oxidation catalyst. Thus the RCEC satisfies the BACT requirement for POC emissions.

- Heat Recovery Steam Generators (HRSGs)

  The HRSG duct burners will be of low-NO_x design, which minimizes incomplete combustion and therefore the POC emission rate. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for SO_2 for combined cycle gas turbines with an output rating of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will burn exclusively PUC-regulated natural gas with an expected average sulfur content of 0.25 grains per 100 scf, which will result in minimal SO_2 emissions. This corresponds to an SO_2 emission factor of 0.0007 lb/MM BTU. This meets the current BACT 2 specification 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 sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0007 lb/MM BTU. This meets the current BACT 2 specification for SO_2.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT for PM_{10} for combined cycle gas turbines with rated output of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will utilize exclusively PUC-regulated natural gas with an average sulfur content of 0.25 gr/100 scf, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Heat Recovery Steam Generators (HRSGs)

  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 ≤ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Cooling Towers

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

  The proposed Cooling Towers will also be equipped with drift eliminators with a drift rate of 0.0005%. This meets BACT for PM_{10}.

Fire Pump Diesel Engine

Based upon 24 hour per day operation under emergency conditions, the proposed fire pump diesel engine triggers BACT for NO_x, POC, and CO, since its potential to emit for each of those pollutants exceeds 10 pounds per day. The current District BACT limits and the specifications for the proposed engine are summarized in Table 6. The applicant will be required by permit conditions to select and install an engine that satisfies BACT for all pollutants listed.

Table 6 District BACT Limits and Proposed Fire Pump Diesel Engine Specifications

Pollutant	District BACT Specifications[a] (g/bhp-hr)	S-6 Engine[b] Specifications (g/bhp-hr)
NOx (as NO_2)	6.9	4.27
CO	2.75	0.33
POC	1.5	0.32
SO_2	Ultra-Low Sulfur Oil	0.005[c]
PM_{10}	Ultra-Low Sulfur Oil	0.12[c]

[a] BACT 2 ("achieved in practice") per District BACT Guideline 96.1.2, "IC Engine – Compression Ignition ≥ 175 hp output rating"

[b] emission rates specified by applicant

[c] permit conditions will require the use of ultra-low sulfur oil (15 ppm by weight) at S-6 engine

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NO_x (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NO_x.

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 surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant.

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 RCEC will emit less than 35 tons of POC per year, the POC emissions were offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302.

NO_x Offsets

Because the RCEC will emit greater than 35 tons per year of Nitrogen Oxides (NO_x) from permitted sources, the applicant provided 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 provided POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM_{10} Offsets

Because the total PM_{10} emissions from permitted sources will not exceed 100 tons per year, the RCEC does not trigger the PM_{10} offset requirement of District Regulation 2-2-303.

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 allows for the voluntary offsetting of SO$_2$ emission increases of less than 100 tons per year. The applicant has opted not to provide such emission offsets.

Offset Package

Table 7 summarizes the offset obligation of the RCEC. The emission reduction credits presented in Table 8 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 under the applications cited in the table footnotes. If the quantity of offsets issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated below, Calpine has surrendered valid emission reduction credits to offset the emission increases from the permitted sources proposed for the RCEC project.

Table 7 Emission Reduction Credits Surrendered for RCEC (ton/yr)

Valid Emission Reduction Credits	POC	NO$_x$
Banking Certificate #, Owner[a]		
855, Calpine		53.11
815, Calpine	80.325	49.864
Total ERC's Identified	80.325	102.974
Permitted Source Emission Limits	28.5	134.6
Offsets Required per BAAQMD Regulations	28.5	154.80
Outstanding Offset Balance	**+51.825[b]**	**-51.825[b]**

[a] These Banking Certificates originated from the following locations:

Certificate	Company	Location	Original Issue Date	Original Cert.
#855	PG&E	San Francisco	9/30/85	#14*
#815	Pacific Refining	Hercules	1/19/01	#558**

* *Certificate #14 (#671) was generated by the shutdown of Potrero Units 1&2 (Boilers S-3, S-4, S-5; B&W 500,000 pounds per hour) at the Potrero Power Plant facility.*

** *Certificate #558 (#728) was generated by the closure of the Pacific Refining Company in Hercules. The credits resulted from the shutdown of process heaters (S-3,4,5,6,8,9,10,12,13) and a safety flare (S-76).*

[b] surplus POC credits used to offset NO$_x$ emission increases per District Regulation 2-2-302.2

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the RCEC 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 RCEC facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards 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. The entire PSD air quality impact analysis is contained in Appendix E.

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. However, RCEC has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions.

Table 8 Maximum Predicted Ambient Impacts of Proposed RCEC ($\mu g/m^3$)

[maximums are in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	119.2	77	9.5	62.4	**226.8**	19
	annual	—	—	—	—	**0.14**	1.0
CO	1-hour	**1977**	1069	6.5	36.5	134.7	2000
	8-hour	**348**	178	—	—	5.7	500
PM_{10}	24-hour	—	—	2.9	**3.2**	2.94	5
	annual	—	—	—	—	**0.15**	1

Because the maximum modeled project impacts for annual average NO_2, 1-hour & 8-hour average CO, and 24-hour & annual average PM_{10} did not exceed their corresponding significance levels for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded per District regulation 2-2-414 is not required. Table 9 summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed RCEC for the NO_2 1-hour impact that exceeds the significance level. As shown in Table 9, the worst-case NOx emissions from RCEC will not cause or contribute to an exceedance of the California ambient air quality standard for 1-hour NO_2.

Table 9
Applicable California and National Ambient Air Quality Standards (AAQS) and Ambient Air Quality Levels from the Proposed RCEC (μg/m³)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	143	227	370	470	---

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the RCEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the RCEC are summarized in Table 2. In accordance with the requirements of the BAAQMD Regulation 2-5 and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing approved air pollutant dispersion models.

Table 10 Health Risk Assessment Results

Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

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

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 PSD air quality impact analysis insures that the proposed facility will comply with this Regulation by concluding that the Russell City Energy Center will not interfere with the attainment or maintenance of applicable federal or state health-based ambient air quality standards for NO_2, CO and PM_{10}.

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 RCEC has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, S-5 Cooling Tower and S-6 Fire Pump Diesel Engine.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements

As the lead agency under CEQA for the proposed RCEC Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC's CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-405, this Preliminary Determination of Compliance (PDOC) serves as the APCO's Preliminary determination that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The PDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-404, this PDOC is subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The Authority to Construct, when issued by the District, will be the PSD permit for the RCEC.

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

A risk screening analysis was performed to estimate the health risk resulting from the toxic air contaminant (TAC) emissions from the RCEC. Results from this analysis indicate that the maximally exposed individual cancer risk is estimated at 0.7 in a million, the chronic non-cancer hazard index at 0.007 in a million, and acute non-cancer hazard index at 0.024 in million. Therefore the RCEC will be in compliance the requirements of Regulation 2-5-301. Furthermore, the proposed controls are considered to be toxic best available control technology (TBACT).

Regulation 2, Rule 6: Major Facility Review

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

Regulation 2, Rule 7: Acid Rain

The RCEC gas turbine units and heat recovery steam generators 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), RCEC 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, auxiliary boiler, and emergency generator set 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 (Gas Turbine and HRSG Duct Burners) is 0.0032 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 8,000 mg/l and corresponding maximum PM_{10} emission rate of 2.83 lb/hr, the proposed 9-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 conditions of certification imposed by the California Energy Commission will include requirements for 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 slip emissions from the proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

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

The use of solvents for cleaning and maintenance at the RCEC 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 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines, HRSG duct burners, and firepimp engine are not expected to cause ground level SO_2 concentrations in excess of the limits specified in Regulation 9-1-301 and should easily comply with section 302.

<u>Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations</u>
The proposed combustion gas turbines (each rated at 2038.6 MM BTU/hr, HHV) and HRSG duct burners (each rated at 200 MM BTU/hr, HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.0 ppmvd @ 15% O_2. The proposed fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 2.02 MM BTU/hr, based upon a maximum rated output of 300 bhp.

<u>Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters</u>
The proposed S-2 & S-4 HRSGs are subject to the emission concentration limits of Regulation 9, Rule 7, section 301 which limits NO_x emissions to 30 ppmv, dry @ 3% O_2 and CO emissions to 400 ppmv, dry @ 3% O_2. To determine if the HRSG duct burners comply with these NO_x emission limits, it would be necessary to install a NOx CEM upstream of the HRSG duct burners

since the HRSGs and turbines exhaust through a common stack. Because the combined exhaust from the turbines and HRSGs are subject to a much more stringent BACT limit of 2.0 ppmvd @ 15% O_2, it is reasonable to conclude that the HRSG duct burners comply with the emission limits of Regulation 9, Rule 7. As a practical matter, the HRSG duct burners are therefore subject to Regulation 9, Rule 9.

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

The proposed 300 hp fire pump diesel engine is exempt from Sections 301, 302 and 502 of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The proposed emergency generator will comply with Regulation 9-8-330 which allows emergency use for unlimited hours, and limits non-emergency use to 50 hours per year.

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 2.0 ppmvd @ 15% O_2, they will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: Standards of Performance for New Stationary Sources

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978", Subpart GG "Standards of Performance for Stationary Gas Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized below:

Source	Requirement	Emission Limitation	Compliance Verification
Gas Turbines and HRSGs	Subpart Da		
	40 CFR 60.44a(a)(1)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 0.0074 lb/NOx/MM BTU
	40 CFR 60.44a(a)(2)	25% reduction of potential NOx emission concentration	SCR Systems will comply with this reduction requirement
	40 CFR 60.44a(d)(1)	1.6 lb NOx/MW-hr	0.055 lb NOx/MW-hr at nominal plant rating of 600 MW
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Sources limited by permit condition to 2.0 ppmv NOx @ 15% O_2, dry
Firepump Diesel Engine	Subpart IIII		
	40 CFR 60	7.8 nmhc+NO_x, 2.6 CO, 0.40 PM_{10} (g/HP-hr) for 2008 and earlier engines	S-6 Firepump Engine will comply with required emission limits. See Table 6.

State Requirements

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

The S-6 Firepump Engine is subject to and will be in compliance with the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines contained in Title 17 of the California Code of Regulations Section 93115. The allowable operating hours and recordkeeping requirements contained in the ATCM will be included in the Permit Conditions.

V 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, shutdown and combustor tuning. If the CO and NO_x 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_x 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, 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 and/or oxidation catalysts in place. Commissioning activities include, but are not limited to the testing of the gas turbines, adjustment of control systems, and the cleaning of the HRSG steam tubes. Permit conditions 1 through 12 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 applicable short-term ambient air quality standard.

Russell City Energy Center
Permit Conditions

(A) 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 consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Warm and Hot 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 20(b) and 20(d)
Gas Turbine Cold Start-up Mode:	The lesser of the first 360 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 20(b) and 20(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 20(b) through 20(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Combustor: Tuning Mode	The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are perfomed, as recommended by the gas turbine manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst are not operating during the tuning operation.
Gas Turbine Cold Start-up:	A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown
Gas Turbine Hot Start-up:	A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown
Gas Turbine Warm Start-up:	A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds

Benzo[a]anthracene
Benzo[b]fluoranthene
Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene

Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners), P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems during the commissioning period
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center

(B) Applicability:

Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 50 shall apply after the commissioning period has ended.

Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.
2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1 & S-3

Gas Turbines combustors and S-2 & S-4 Heat Recovery Steam Generators duct burners 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, owner/operator shall install, adjust, and operate the A-2 & A-4 Oxidation Catalysts and A-1 & A-3 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.
4. Coincident with the steady-state operation of A-1 & A-3 SCR Systems and A-2 & A-4 Oxidation Catalysts pursuant to conditions 3, 9, 10 (except for S-6), and 11, the owner/operator shall operate the Gas Turbines (S-1 & S-3) and the HRSGs (S-3 & S-4) in such a manner as to comply with the NO_x and CO emission limitations specified in conditions 20(a) through 20(d).
5. The owner/operator of the RCEC shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 & S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, 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) and HRSGs (S-2 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1 or S-3) sooner than 28 days after the District receives the commissioning plan.
6. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 8, 9, 10, and 11 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), HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.
7. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in condition 6 prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 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 and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

9. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 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 and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

10. 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), Heat Recovery Steam Generators (S-2 & S-4) and S-6 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. The owner/operator shall not operate the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) in a manner such that the combined pollutant emissions from these sources will 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).

NO_x (as NO_2)	4,805 pounds per calendar day	400 pounds per hour
CO	20,000 pounds per calendar day	5,000 pounds per hour
POC (as CH_4)	495 pounds per calendar day	
PM_{10}	432 pounds per calendar day	
SO_2	298 pounds per calendar day	

12. No less than 45 days prior to the end of the Commissioning Period, the Owner/Operator shall conduct District and CEC approved source tests using certified continuous emission monitors to determine compliance with the emission limitations specified in condition 20. The source tests 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 and shall include at least one cold start, one warm start, and one hot start. Twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed

source test plan designed to satisfy the requirements of this 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 30 days of the source testing date.

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

13. The owner/operator shall fire the Gas Turbines (S-1 & S-3) and HRSG Duct Burners (S-2 & S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-4 shall sample and analyze the gas from each supply source at least once every 30 consecutive days to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the RCEC. (BACT for SO_2 and PM_{10})
14. The owner/operator shall not operate the units such that 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) exceeds 2,238.6 MM BTU (HHV) per hour. (PSD for NO_x)
15. The owner/operator shall not operate the units such that 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) exceeds 53,726 MM BTU (HHV) per day. (PSD for PM_{10})
16. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) exceeds 35,708,858 MM BTU (HHV) per year. (Offsets)
17. The owner/operator shall not fire the HRSG duct burners (S-2 & S-4) unless its associated Gas Turbine (S-1 & S-3, respectively) is in operation. (BACT for NO_x)
18. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-1 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
19. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-3 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
20. The owner/operator shall ensure that the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (BACT, PSD, and Regulation 2, Rule 5)
    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-1 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-3 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired.
    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.0 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 and P-2 each shall not exceed 20 pounds per hour or 0.009 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 4.0 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 and P-2 each shall not exceed 5 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-2 and A-4 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2 and A-4 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 30. (Regulation 2-5)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.86 pounds per hour or 0.00128 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 & P-2 each shall not exceed 1.55 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 each shall not exceed 8.64 pounds per hour or 0.0042 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 11.64 pounds per hour or 0.0052 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up does not exceed the limits established below. (PSD)

	Cold Start-Up Combustor Tuning		**Hot Start-Up**		**Warm Start-Up**	
Pollutant	**lb/hr**	**lb/start-up**	**lb/hr**	**lb/start-up**	**lb/hr**	**lb/start-up**
NO_x (as NO_2)	97.2	480.0	83.8	240	97.2	240
CO	1348.8	5,028	1154.2	2514	1348.2	2514
POC (as CH_4)	32	83	35	35.3	45	79

22. The owner/operator shall not perform combustor tuning on Gas Turbines more than once every rolling 365 day period for each S-1 and S-3. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. (Offsets, Cumulative Emissions)

23. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any calendar day:

(a) 1,553 pounds of NO_x (as NO_2) per day (Cumulative Emissions)
(b) 10,774 pounds of CO per day (PSD)
(c) 295 pounds of POC (as CH_4) per day (Cumulative Emissions)
(d) 626 pounds of PM_{10} per day (PSD)

(e) 74 pounds of SO_2 per day (BACT)

24. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a) 134.6 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b) 389.3 tons of CO per year	(Cumulative Increase, PSD)
(c) 28.5 tons of POC (as CH_4) per year	(Offsets)
(d) 86.8 tons of PM_{10} per year	(Cumulative Increase, PSD)
(e) 12.2 tons of SO_2 per year	(Cumulative Increase, PSD)

25. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1 and P-2 combined to exceed 7 tons in any consecutive 12 month period. (Basis: PSD)

26. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per condition 29) from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4) combined to exceed the following limits:

formaldehyde	10,912 pounds per year
benzene	226 pounds per year
Specified polycyclic aromatic hydrocarbons (PAHs)	1.8 pounds per year

unless the following requirement is satisfied:

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

27. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a) and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods) for all of the following parameters:
    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.
    (b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_x) concentration, and Carbon Monoxide (CO) concentration at exhaust points P-1 and P-2.
    (c) Ammonia injection rate at A-1 and A-3 SCR Systems

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:

(d) Heat Input Rate for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1 and P-2.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 27(d) and 27(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(h) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(i) 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 and all four sources (S-1, S-2, S-3 and S-4) combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined and the auxiliary boiler.

(k) 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 four sources (S-1, S-2, S-3 and S-4) combined.

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

28. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c), 23(d), 23(e), 24(c), 24(d), 24(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. The owner/operator shall use the actual heat input rates measured pursuant to condition 27, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under

condition 31 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3 & S-4) 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) combined

(Offsets, PSD, Cumulative Increase)

29. To demonstrate compliance with Condition 26, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 35,708,858 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1 and S-3 Gas Turbines and/or S-2 and S-4 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (Regulation 2, Rule 5)

30. Within 60 days of start-up of the RCEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2 or A-4 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 45 days of conducting the tests. (Regulation 2, Rule 5)

31. Within 60 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 20(a), 20(b), 20(c), 20(d), 20(f), 20(g), and 20(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and 20(d), and to verify the accuracy of the continuous emission monitors required in condition 27. 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. The owner/operator shall submit the

source test results to the District and the CEC CPM within 45 days of conducting the tests. (BACT, offsets)

32. 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 45 days of conducting the tests. (BACT)

33. Within 60 days of start-up of the RCEC and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 26 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	$\leq$	6.4 pounds/year and 2.9 pounds/hour
Formaldehyde	$\leq$	30 pounds/year and 0.21 pounds/hour
Specified PAHs	$\leq$	0.011 pounds/year

(Regulation 2, Rule 5)

34. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 31. If this SAM mass emission limit of condition #25 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

35. Within 60 days of start-up of the RCEC and on a semi-annual basis (twice per year) thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 25. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. After acquiring one year of source test data on these sources, the owner/operator may petition the District to reduce the test frequency to an annual basis if test result variability is sufficiently low as determined by the District. The owner/operator shall submit the source test results to the District and the CEC CPM within 45 days of conducting the tests. (PSD)

36. The owner/operator of the RCEC 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)

37. The owner/operator of the RCEC 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)
38. The owner/operator of the RCEC 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)
39. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 145 feet above grade level at the stack base. (PSD, Regulation 2-5)
40. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)
41. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 30, 31, 33, 34, and 44. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)
42. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)
43. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Russell City Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)
44. The owner/operator shall ensure that the Russell City Energy Center complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

Permit Conditions for Cooling Towers

45. The owner/operator shall properly install and maintain the S-5 cooling tower to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return

to the wastewater facility shall not be higher than 8,000 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

46. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Russell City 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. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. The CEC CPM may require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

Permit Conditions for S-6 Fire Pump Diesel Engine

47. The owner/operator shall not operate S-6 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations,subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets)

48. The owner/operator shall operate S-6 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))

49. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)

50. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
    a. Hours of operation for reliability-related activities (maintenance and testing).
    b. Hours of operation for emission testing to show compliance with emission limits.
    c. Hours of operation (emergency).
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage for each engine(s).

    (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

VI Recommendation

The APCO has concluded that the proposed Russell City 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 Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute, with efficiency drift eliminators, make and model to be determined.

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 3400 hp, 2.02 MMBtu/hr rated heat input.

Pursuant to District Regulation 2-3-404, this document is subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Russell City Energy Center. The public inspection and comment period will end 30 days after the date of such publication. Written comments on this document should be directed to:

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

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°F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8740 dscf/MM Btu
natural gas higher heating value:	1050 Btu/dscf

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

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

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

Table A-1
Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
Pollutant	lb/MM Btu	lb/hr	lb/MM Btu	lb/hr
Nitrogen Oxides (as NO_2)	0.00735[a]	14.98	0.00735[a]	16.45
Carbon Monoxide	0.0090[b]	18.24	0.0090[b]	19.96
Precursor Organic Compounds	0.00128	2.61	0.00128	2.86
Particulate Matter (PM_{10})	0.00424	8.64	0.0052	11.64
Sulfur Dioxide	0.000693	1.41	0.000693	1.55

[a] based upon stack concentration of 2.0 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 and A-3 Selective Catalytic Reduction Systems with ammonia injection.

[b] based upon the permit condition emission limit of 4 ppmvd CO @ 15% O_2 that reflects abatement by proposed A-2 and A-4 Oxidation Catalysts.

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°F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8740 dscf/MM Btu
natural gas higher heating value:	1050 Btu/dscf

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

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

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

Table A-1
Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
Pollutant	lb/MM Btu	lb/hr	lb/MM Btu	lb/hr
Nitrogen Oxides (as NO_2)	0.00735[a]	14.98	0.00735[a]	16.45
Carbon Monoxide	0.0090[b]	18.24	0.0090[b]	19.96
Precursor Organic Compounds	0.00128	2.61	0.00128	2.86
Particulate Matter (PM_{10})	0.00424	8.64	0.0052	11.64
Sulfur Dioxide	0.000693	1.41	0.000693	1.55

[a] based upon stack concentration of 2.0 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 and A-3 Selective Catalytic Reduction Systems with ammonia injection.

[b] based upon the permit condition emission limit of 4 ppmvd CO @ 15% O_2.that reflects abatement by proposed A-2 and A-4 Oxidation Catalysts.

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 2.0 ppmv, dry @ 15% O_2. This emission concentration will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.042 ppmv NO_x, dry @ 0% O_2

$(7.042/10^6)$(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8740 dscf/MM Btu)

= 0.00735 lb NO_2/MM Btu

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

(0.00735 lb/MM Btu)(2038.6 MM Btu/hr) = **14.98 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 gas turbine and HRSG and is calculated as follows:

(0.00735 lb/MM Btu)(2238.6 MM Btu/hr) = **16.45 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 4 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(4 ppmv)(20.95 - 0)/(20.95 - 15) = 14.08 ppmv, dry @ 0% O_2

$(14.08/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8740 dscf/MM Btu)

= 0.0090 lb CO/MM Btu

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

(0.0090 lb/MM Btu)(2038.6 MM Btu/hr) = **18.24 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:

(0.0090 lb/MM Btu)(2238.6 MM Btu/hr) = **19.96 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Combustion Gas Turbine

The POC emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled emission limit of 1 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The POC emission factor corresponding to this emission concentration is calculated as follows:

(1 ppmv)(20.95 - 0)/(20.95 - 15) = 3.521 ppmv, dry @ 0% O_2

$(3.521/10^6)$(lbmol/385.3 dscf)(16 lb CH_4/lbmol)(8740 dscf/MM Btu)
= **0.00128 lb POC/MM Btu**

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

(0.00128 lb/MM Btu)(2038.6 MM Btu/hr) = **2.61 lb POC/hr**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The POC 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:

(0.00128 lb/MM Btu)(2238.6 MM Btu/hr) = **2.86 lb POC/hr**

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Combustion Gas Turbine and HRSG Combined

The applicant has determined a PM_{10} emission factor of 0.0052 lb/MMBtu at maximum load for the gas turbine and HRSG. It is assumed that this PM_{10} emission factor includes secondary PM_{10} formation of particulate sulfates. The corresponding PM_{10} emission rate is:
(0.0052 lb/MMBtu)/(2238.6 MM Btu/hr) = **11.64 lb/hr**

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

PM_{10} mass emission rate:	11.64 lb/hr
flow rate:	4,038,946 lb/hr @ 11.8% O_2 and 180°F
moisture content:	8.7% by volume

Converting flow rate to standard conditions:
(4,038,946 lb/hr)(1 hr/60 min)(385.3 cf/lb mol)(1 mol/28.39) = 915,556 acfm
(915,556 acfm)([70 + 460 °R]/[180 + 460 °R])(1 – 0.087) = 692,232 dscfm

Converting to grains/dscf:
(11.64 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(692,232 dscfm) = 0.00196 gr/dscf

Converting to 6% O_2 basis:
(0.00196 gr/dscf)[(20.95 - 6)/(20.95 – 11.8)] = 0.0032 gr/dscf @ 6% O_2

Combustion Gas Turbine

The PM_{10} emission factor is based upon the applicant's assumption of 3 lb/hr for the HRSG PM_{10} emission rate. The corresponding PM_{10} emission factor is therefore:
([11.64-3] lb PM_{10}/hr)/(2038.6 MM Btu/hr) = **0.00424 lb PM_{10}/MM Btu**

SULFUR DIOXIDE EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon an expected average natural gas sulfur content that will average 0.25 grains per 100 scf and a higher heating value of 1050 Btu/scf as specified by PG&E. Although the maximum sulfur content can be as high as 1.0 grain per 100 scf, the actual sulfur content is likely to be much less.

The sulfur emission factor is calculated as follows:
(0.25 gr/100scf)(10^6 Btu/MM Btu)(2 lb SO_2/lb S)/[(7000 gr/lb)(1030 Btu/scf)(100 scf)]
= **0.000693 lb SO_2/MM Btu**

The corresponding mass SO_2 emission rate at the maximum combined firing rate of 2238.6 MM Btu/hr is:
(0.000693 lb SO_2/MM Btu)(2238.6 MM Btu/hr) = 1.55 lb/hr

The corresponding SO_2 mass emission rate at the maximum gas turbine firing rate of 2038.6 MM Btu/hr is:
(0.000693 lb SO_2/MM Btu)(2038.6 MM Btu/hr) = 1.41 lb/hr

This is converted to an emission concentration as follows:
(0.000693 lb SO_2/MM Btu)(385.3 dscf/lb-mol)(lb-mol/64.06 lb SO_2)(10^6 Btu/8740 dscf) = 0.48 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

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 and HRSG Duct Burners

Contaminant	Emission Factor (lb/MM scf)
Acetaldehyde[d]	6.86E-02
Acrolein	2.37E-02
Ammonia[c]	6.63
Benzene[d]	1.36E-02
1,3-Butadiene[d]	1.27E-04
Ethylbenzene	1.79E-02
Formaldehyde[d]	9.17E-01
Hexane	2.59E-01
Naphthalene	1.66E-03
PAHs[b,d]	1.06E-04
Propylene	7.70E-01
Propylene Oxide[d]	4.78E-02
Toluene	7.10E-02
Xylene	2.61E-02

[a] California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program, mean values.
[b] CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.
[c] based upon maximum allowable ammonia slip of 5 ppmv, dry @ 15% O_2 for A-1 and A-3 SCR Systems
[d] carcinogenic compound

Table A-3
TAC Emission[a] Factors Cooling Tower

Contaminant	Emission Factor (ppm)	Emission Factor (lb/hr)
Ammonia	60	2.12E-02
Arsenic	0.05	1.77E-05
Cadmium	0.08	2.83E-05
Chromium (Hex)	0.41	1.45E-04
Copper	0.61	2.15E-04
Lead	0.19	6.71E-05
Manganese	0.84	2.94E-04
Mercury	0.0006	2.12E-07
Nickel	0.47	1.66E-04
Selenium	0.07	2.47E-05
Zinc	1.92	6.78E-04

[a] Based upon maximum drift loss of 353.2 lb/hr and operation of cooling tower at maximum water circulation rate of 141,252 gallons per minute.

AMMONIA EMISSION FACTOR

Combustion Gas Turbine & Heat Recovery Steam Generator

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 5 ppmvd @ 15% O_2.
(5 ppmvd)(20.95 - 0)/(20.95 - 15) = 17.61 ppmv NH_3, dry @ 0% O_2
$(17.61/10^6)$(1 lbmol/385.3 dscf)(17 lb NO_2/lbmol)(8710 dscf/MM Btu) = **0.0068 lb NH_3/MM Btu**

The NH_3 mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:
(0.0068 lb/MM Btu)(2038.6 MM Btu/hr) = **13.80 lb NH_3/hr**

The NH_3 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:
(0.0066 lb/MM Btu)(2238.6 MM Btu/hr) = **15.15 lb NH_3/hr**

Table A-4
Regulated Air Pollutant Emission Factors for Fire Pump Diesel Engine

Pollutant	Emission Factor	
	g/bhp-hr[a]	lb/hr[b]
Nitrogen Oxides (as NO_2)	4.27	2.82
Carbon Monoxide	0.33	0.22
Precursor Organic Compounds	0.32	0.21
Particulate Matter (PM_{10})	0.12	0.08
Sulfur Dioxide	0.005	0.003

[a] specified by applicant
[b] based upon maximum rated output of 300 bhp

Appendix B

Individual and combined heat input rate limits for the gas turbines, HRSGs, and fire pump engine 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 and S-3 Gas Turbines, each	2,038.6	48,926.4[a]	17,054,433[b]
S-1 CTG and S-2 HRSG, each S-3 CTG and S-4 HRSG, each	2238.6[c]	53,726[d]	17,854,429[e]
S-7 Diesel Engine	2.02	5.1[f]	101[g]

[a] based upon specified maximum rated heat input of 2038.6 MM Btu/hr and 24 hour per day operation

[b] based upon maximum fuel usage of 16,671 MMscf fuel usage per year at 1023 Btu/scf. This is equivalent to 8366 hours per year of operation. (17,054,433 Btu/yr/2038.6 MM Btu/hr)

[c] maximum combined firing rate for gas turbine and HRSG duct burners (200 MM Btu/hr)

[d] based upon maximum duct burner firing of 24 hours per day; calculated as:
(24 hr/day)(2,238.6 MM Btu/hr) = 53,726.4 MM Btu/day

[e] based upon maximum duct burner fuel usage of 782.01 MMscf fuel per year usage at 1023 Btu/scf. This is equivalent to 4000 hours per year of HRSG operation. (800,000 Btu/yr/200 MM Btu/hr)

[f] based upon maximum engine operation of 2.5 hours per day (non-emergency); calculated as:
(2.5 hr/day)(2.02 MM Btu/hr) = 5.1 MM Btu/day

[g] based upon 52 hours of non-operation operation at full load; calculated as:
(50 hr/yr)(2.02 MM Btu/hr) = 101 MM Btu/yr

B-1.0 Gas Turbine Start-Up/Turbine Tuining, and Shutdown Emission Rate Estimates

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound mass emission rates from a gas turbine occur during start-up periods. The PM_{10} and sulfur dioxide emissions are a function only of fuel use rate and do not exceed typical full load emission rates during start-up. The NO_x, CO, and UHC (POC) emission rates shown in Table B-3 are specified by RCEC based upon gas turbine vendor estimates.

Table B-2

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

Pollutant	Cold Start-Up/Combustor Tuning[a]		Hot Start-Up[b]		Warm Start-Up[c]	
	lb/hr	lb/start-up[f]	lb/hr	Lb/start-up[f]	lb/hr	lb/start-up[f]
NO_x (as NO_2)	97.2	480.0	83.8	240	97.2	240
CO	1348.8	5028	1154.2	2514	1348.2	2514
UHC (as CH_4)	14.9	96	14.9	44.7	14.9	48
PM_{10}[d]	10.6	63.6	10.6	31.8	10.6	31.8
SO_x (as SO_2)[e]	2	12	2	6	2	6

[a] cold start not to exceed six hours (360 minutes); by definition, occurs after turbine has been inoperative for at least 48 hours. Combustor tuning not to exceed six hours (360 minutes)

[b] hot start not to exceed 3 hours (180 minutes); by definition, occurs within 8 hours of a shutdown

[c] warm start not to exceed 3 hours (180 minutes); by definition occurs between 8 and 48 hours of a shutdown

[d] as a conservative estimate, based upon full load emission factor of 0.00424 lb PM_{10}/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr

[e] based upon full load emission factor of 0.000693 lb SO_2/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr

[f] emissions are not calculated by multiplying hourly rate by number of startup hours for NO_x, CO and UHC. These startup emissions are specified by applicant based on operational data.

Table B-3 is a comparison of baseload emission rates and shutdown emission rates specified by the applicant.

Table B-3 Gas Turbine Shutdown Emission Rates

Pollutant	Baseload Emission Rate (lb/hr)[a]	Shutdown Emission Rate	
		lb/hr	lb/shutdown[b]
NO_x (as NO_2)	16.45	28.9	80
CO	19.96	224.2	902
UHC (as CH_4)	2.86	6.7	16

[a] emission rates for gas turbine w/duct burner firing

[b] Shutdown not to exceed 30 minutes. Emissions are not calculated by multiplying hourly rate by 0.5 hours for shutdown. These emissions are specified by applicant based on operational data.

B-2.0 Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

The air pollutant emission rates shown in **Table B-4** were calculated in Application #2896 (original application for Authority to Construct). RCEC will be subject to the emission rates as the basis of permit condition limits and emission offset requirements. These rates are 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 or shutdowns. Instead, the facility must comply with rolling consecutive twelve-month mass emission limits at all times. The mass emission limits were originally based upon the emission estimates calculated for the following power plant operating envelope.

- 2,800 hours of baseload (100% load) operation per year for each gas turbine
- 5,260 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 27 hot start-ups per gas turbine per year
- 9 warm start-ups per gas turbine per year
- 12 cold start-ups per gas turbine per year

Table B-4: Maximum Annual Regulated Air Pollutant Emissions for Gas Turbines HRSGs[a], Natural Gas Engine, Fire Pump Engine, and Cooling Tower

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 Gas Turbines (520 hr/yr of hot start-ups)	41,600	312,693	8,320	4,680	712
S-1 & S-3 Gas Turbines (312 hr/yr of cold start-ups)	24,960	174,304	4,992	2,808	427
S-1 & S-3 Gas Turbines (13,688 total hours[a] @ 100% load)	194,506[b]	234,795[c]	33,809[c]	123,192[c]	18,753[c]
S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs (3000 total hours[a] w/duct burner firing and steam injection power augmentation)	46,950[d]	56,660[e]	8,160[e]	36,000[e]	4,530[e]
S-5 Cooling Tower				6,132[f]	
S-6 Diesel Engine[g] (30 hours per year)	117	71	14	4	3
Total Emissions (lb/yr)	308,488	778,523	55,579	172,817	24,426
(ton/yr)	**154.2[h]**	**389.3[i]**	**27.8[j]**	**86.4[k]**	**12.2**

a total combined firing hours for both turbines

b based upon the heat input rate of 1,979.4 MMBtu/hr for each gas turbine and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2038.6 MMBtu/hr)

c based upon the heat input rate of 1,979.4 MM Btu/hr for each gas turbine (heat input rate has been revised to 2038.6 MMBtu/hr)

d based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2238.6 MMBtu/hr)

e based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train (heat input rate has been revised to 2238.6 MMBtu/hr)

f based upon an emission rate of 0.7 lb/hr operated 8760 hr/yr.

Circulation Rate: 135,000 gpm
Drift Rate: 0.0005%
Water Mass Rate: 67,554,000 pph
(135,000 gal/min)(60 min/hr)(8.34 lb/gal)
TDS = 0.7 x 10^6/(67,554,000 x 0.000005) = 2072 ppm (maximum)

(The new cooler tower has a TDS of 8,000 ppm and an emission rate of 24,790 lb PM/yr [2.83 lb/hr X 8760 hr/yr]. The applicant is willing to be subject to maximum facility PM_{10} emissions as previously calculated)

g emission rates from vendor guarantee

h applicant elected to offset 134.6 tons of NO_x. It is specified by the applicant and is stated to reflect real operating scenarios. Permit conditions will limit total plant NO_x emissions to 134.6 tons per year

i adjusted from previous calculation by 4/6 for turbine CO exhaust (new BACT for turbine CO at 4 ppm from 6 ppm)

j applicant elected to offset 28.5 tons of POC

k PM_{10} emissions increased to 86.8 tons per year

B-3.0 Fire Pump Diesel Engine Emissions

Table B-5 Regulated Air Pollutant Emissions for Fire Pump Diesel Engine

Pollutant	Emission Factor		Annual Emissions[a]	
	g/bhp-hr	lb/hr	lb/yr	ton/yr
Nitrogen Oxides (as NO_2)	4.27	2.82	141	0.071
Carbon Monoxide	0.33	0.22	10.9	0.0055
Precursor Organic Compounds	0.32	0.21	10.6	0.0053
Particulate Matter (PM_{10})	0.12	0.079	3.97	0.0020
Sulfur Dioxide	0.005	0.0033	0.165	0.00008

[a] based upon 50 hours of operation per year for testing and maintenance and maximum rated output of 300 bhp

Table B-6
Worst-Case Toxic Air Contaminant Emissions for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Annual Emissions[a] (lb/yr)
Benzene	9.33E-04	0.0942
Toluene	4.09E-04	0.0413
Xylenes	2.85E-04	0.0288
Propylene	2.58E-03	0.2606
1,3-Butadiene	3.91E-05	0.0039
Formaldehyde	1.18E-03	0.1192
Acetaldehyde	7.67E-04	0.0775
Acrolein	9.25E-05	0.0093
Total PAHs	1.68E-04	0.0170
Diesel particulate	3.93E-02	3.97

[a] based upon assumed maximum rated heat input of 2.02 MM BTU/hr and maximum 50 operating hours per year

B-4.0 Cooling Tower PM_{10} Emissions

Cooling tower circulation rate:	141,352 gpm
maximum total dissolved solids:	8000 ppmw
Drift Loss:	353.2 lb/hr

PM_{10} = (8000 ppmw)(353.2 lb/hr)/(10^6)
= 2.83 lb/hr
= 67.8 lb/day (24 hr/day operation)
= 27,790 lb/yr (8,760 operating hours per year)
= 12.4 ton/yr

Drift Rate = (353.2 lb/hr)/(141,352 gal/min)(60 min/hr)(8.33 lb/gal) = 0.0005%

B-5.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1 & S-3 *Gas Turbines* and S-2 & S-4 HRSGs are summarized in **Table B-7.** 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 17,854,429 MM BTU per year for each gas turbine/HRSG power train. The derivation of the emission factors is detailed in Appendix A.

Table B-7
Worst-Case Annual TAC Emissions for Gas Turbines and HRSGs

Toxic Air Contaminant	Emission Factor[a] (lb/MM scf)	lb/yr-power train[b]	ton/yr
Acetaldehyde[c]	1.37E-01	2329	1.16E+00
Acrolein	1.89E-02	321.3	1.61E-01
Ammonia[d]	7.11E+00	120870	6.04E+01
Benzene[c]	1.33E-02	226.1	1.13E-01
1,3-Butadiene[c]	1.27E-04	2.16	1.08E-03
Ethylbenzene	1.79E-02	304.3	1.52E-01
Formaldehyde[c]	9.17E-01	5,456[f]	2.72E+00
Hexane	2.59E-01	4403	2.20E+00
Naphthalene	1.66E-03	28.22	1.41E-02
Propylene	7.71E-01	13107	6.55E+00
Propylene Oxide[c]	4.78E-02	812.6	4.06E-01
Toluene	7.10E-02	1207	6.04E-01
Xylenes	2.40E-02	408	2.04E-01
Total PAHs[e]	1.06E-04	1.8	9.01E-04

[a] CARB CATEF II Database emission factors, mean values
[b] from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4); based upon annual gas usage rate of 17,000MM scf/yr-turbine/HRSG
[c] carcinogenic compounds
[d] based upon the worst-case ammonia slip from the SCR system of 5 ppmvd @ 15% O_2
[e] CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.
[f] reflects oxidation catalyst abatement efficiency of 65% (wt) for formaldehyde

The projected toxic air contaminant emissions from S-5 Cooling Tower are summarized in **Table B-8**. The emissions are based upon a water circulation rate of 141,352 gpm and 8,760 hours of operation per year.

Table B-8 Worst-Case TAC Emissions for Cooling Tower

Toxic Air Contaminant	Emission Factor (lb/hr)	Annual Emission Rate (lb/yr)	(ton/yr)
Ammonia	2.12E-02	185.71	9.29E-02
Arsenic	1.77E-05	0.16	7.75E-05
Cadmium	2.83E-05	0.25	1.24E-04
Chromium (Hex)	1.45E-04	1.27	6.35E-04
Copper	2.15E-04	1.88	9.42E-04
Lead	6.71E-05	0.59	2.94E-04
Manganese	2.94E-04	2.58	1.29E-03
Mercury	2.12E-07	0.00	9.29E-07
Nickel	1.66E-04	1.45	7.27E-04
Selenium	2.47E-05	0.22	1.08E-04
Zinc	6.78E-04	5.94	2.97E-03

B-6.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-9**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-9 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]	67.26	194.65	14.24	37.0	6.1
S-3 CTG and S-4 HRSG[a]	67.26	194.65	14.24	37.0	6.1
Sub-Total	**134.52**	**389.3**	**28.48**	**74.0**	**12.2**
S-5 Cooling Towers	0	0	0	12.40	0
S-6 Diesel Fire Pump Engine	0.071	0.0055	0.0053	0.002	0.00008
Total Facility Emissions	**134.6**	**389.3**	**28.5**	**86.4**	**12.2**

[a] includes gas turbine start-up/combustor tuning and shutdown emissions

Table B-10
Baseload Air Pollutant Emission Rates for Gas Turbines and HRSGs
(Excluding Gas Turbine Start-up and Shutdown Emissions)

	NO_2	CO	POC	PM_{10}	SO_2
Each Gas Turbine (2038.6 MM BTU/hr)					
lb/hr-source	14.98	18.24	2.61	8.64	1.41
lb/day-source	360	438	63	207	34
Each Gas Turbine/HRSG Power Train (2,238.6 MM BTU/hr and 24 hour per day duct burner firing					
lb/hr-power train	16.45	19.96	2.86	11.64	1.55
lb/day-power train	395	479	69	279	37

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-11.**

Table B-11 Maximum Daily Regulated Air Pollutant Emissions per Power Train (lb/day)

Source (operating mode)	NO_2	CO	POC	PM_{10}	SO_2
Gas Turbine (6-hr cold start-up)	480	5028	96	63.6	12
Gas Turbine & HRSG (18 hours full load w/duct burner firing)	296.1	359.3	51.5	215.4	25
Total	**776**	**5387**	**148**	**279**	**37**

Table B-12 summarizes the worst-case daily regulated air pollutant emissions from permitted sources. These are the basis of permit condition daily mass emission limits. The operating scenario assumes simultaneous cold start-up of two gas turbines followed by 18 hours of full load operation with duct burner firing. Cooling tower operates 24 hours per day and the fire pump diesel engine operates for a maximum of 0.5 hours per day for exercising.

Table B-12 Worst-Case Daily Regulated Air Pollutant Facility Emissions from Permitted Sources (lb/day)

Source (Operating Mode)	NO_2	CO	POC	PM_{10}	SO_2
Two Gas Turbines (6-hr cold start-up)	960	10,056	192	127.2	24
Two Gas Turbine/HRSG Power Trains (18 hours @ full load w/*Duct Burner* Firing)	592.2	718.6	103	430.8	50
Gas Turbine/HRSG Powertrain Sub-total	**1552**	**10,774**	**295**	**558**	**74**
S-5 Cooling Tower				68	
S-6 Diesel Fire Pump Engine	1.41	0.11	0.11	0.0017	0.04
Total	**1,553**	**10,774**	**295**	**626**	**74**

[a] daily maximum for these pollutants occur when all four turbines are operating at full load w/duct burner firing

B-7.0 Maximum Facility Emissions During Commissioning Period

Table B-13 summarizes the worst-case 1-hour and 8-hour emission rates for the RCEC during the commissioning period, when the SCR systems and oxidation catalysts are not yet installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the RCEC 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-13
Worst-Case Short-Term NO_2 and CO Emission Rates for Gas Turbines during Commissioning Period[a]

	NO_2	CO	POC	PM_{10}	SO_2
Both Gas Turbines	400 lb/hr	5,000 lb/hr			
Both Gas Turbines	4,805 lb/day	20,000 lb/day	495 lb/day	432 lb/day	297.6 lb/day

[a] data provide by applicant based upon data collected at the Calpine Metcalf Energy Center

B-8.0 Modeling Emission Rates

The emission rates shown in **Table B-14** were used to model the air quality impacts of the RCEC to determine compliance with State and Federal annual ambient air quality standards for NO_2, CO, and PM_{10}. A screening impact analysis of two gas turbine/HRSG duct burner systems, a 9-cell cooling tower, and a diesel fire pump engine emission rates and stack gas characteristics revealed that the worst-case impacts occur under the equipment operating scenarios listed.

TABLE B-14

Averaging Period Emission Rates Used in Modeling Analysis (g/s)

Pollutant Source	Max. (1-hour)	Commis-sioning[a] (1-hour)	Start-up[b] (1-hour)	Start-up[b] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[a] Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time.

[b] Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Appendix C

Emission Offsets

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required for permitted sources. Emission offsets have been provided for NO_x and POC emission increases associated with S-1 Gas Turbine, S-2 HRSG, S-3 Gas Turbine, S-4 HRSG, S-5 Cooling Tower, and S-6 Diesel Engine.

Table C-1 Emission Offset Summary

	NO_2	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	134.6	389.3	28.5	86.4	12.2
Offset Requirement Triggered	Yes	N/A	Yes	No	No
Offset Ratio	1.15[b]	N/A	1.00[c]	N/A	N/A
Offsets Required (tons)	**154.8**	**0**	**28.5**	**0**	**0**

[a]Sum of emission increases from all permitted sources.

[b]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 emissions from permitted sources will exceed 35 tons per year.

[c]Pursuant to District Regulation 2-2-302, an offset ratio of 1.0 applies since the facility POC emissions are less than 35 tons per year.

Appendix D

Health Risk Assessment

As a result of: (1) combustion of natural gas at the proposed Gas Turbines and HRSGs (2) diesel fired fire pump engine and (3) the presence of dissolved solids in the cooling tower water, the proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 2, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, 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) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70 year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, 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. The worst-case assumption is made that the exposure occurs over a one-year period. Per the BAAQMD Regulation 2-5, a project with a total chronic and acute hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table D-1**.

Table D-1
Health Risk Assessment Results

Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

In accordance with the BAAQMD Regulation 2-5, the increased carcinogenic risk, chronic hazard index, and acute hazard index attributed to this project are each considered to be not significant since they are each less than 1.0.

Based upon the results given in Table D-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER

February 7, 2007

BACKGROUND

Russell City Energy Center LLC has submitted a permit application (# 15487) for a proposed 600 MW combined cycle power plant, the Russell City Energy Center (RCEC). The facility is to consist of two natural gas-fired turbines with supplementary fired heat recovery steam generators, one steam turbine and supplemental burners (duct burners), a 9-cell cooling tower, and a diesel fire pump engine. The proposed 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 I, along with the corresponding significant emission rates for air quality impact analysis.

TABLE 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 to 2-2-306)	EPA PSD Significant Emission Rates for major stationary sources (tons/year)
NO_x	134.6	100	40
CO	584.2	100	100
PM_{10}	86.8	100	15
SO_2	12.2	100	40

Table I indicates that the proposed project emissions exceed District significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), and respirable particulate matter (PM_{10}). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table I). Table I shows that the NO_2, CO and PM_{10} ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in Sections 304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

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 impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_2, 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, impacts due to inversion breakup fumigation, and impacts due to shoreline fumigation.

Emissions from the turbines and burners will be exhausted from two 145 foot exhaust stacks and the fire pump will be exhausted from a 15 foot exhaust stack. Emissions from a 9-cell cooling tower will be released at a height of 60 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, turbine startup, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Startup conditions were modeled with one turbine in startup mode, while the other turbine was in normal operation.

The EPA models SCREEN3 and ISCST3 were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using five years of meteorological data (1990 through 1994) collected approximately 6.6 km southeast of the project at the BAAQMD's Union City meteorological monitoring station. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Using 1990-1994 San Leandro ozone monitoring data, the Ozone Limiting Method was employed to convert one-hour NO_x impacts into one-hour NO_2 impacts. (The San Leandro monitoring station is located 8.8 km north of the project) The Ambient Ratio Methodology (with a default NO_2/NO_x ratio of 0.75) was used for determining the annual-averaged NO_2 concentrations. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation and shoreline fumigation were evaluated using the SCREEN3 model.

TABLE 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)	Start-up[2] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[1]Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time. [2]Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

Also shown in Table III are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table III shows that the only impact requiring further analysis is the 1-hour NO_2 modeled impact.

TABLE 3
Maximum predicted ambient impacts of proposed project ($\mu g/m^3$)
[maximums are in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	119.2	77	9.5	62.4	**226.8**	19
	annual	—	—	—	—	**0.14**	1.0
CO	1-hour	**1977**	1069	6.5	36.5	134.7	2000
	8-hour	**348**	178	—	—	5.7	500
PM_{10}	24-hour	—	—	2.9	**3.2**	2.94	5
	annual	—	—	—	—	**0.15**	1

Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," 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 IV lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, the modeled NO_2 impact is well below the preconstruction monitoring threshold.

TABLE 4
PSD monitoring exemption level and maximum impact
from the proposed project for NO_2 ($\mu g/m^3$)

Pollutant	Averaging Time	Exemption Level	Maximum Impact from Proposed Project
NO_2	annual	14	0.14

The District-operated Fremont-Chapel Way Monitoring Station, located 18.3 km southeast of the project, was chosen as representative of background NO_2 concentrations. Table V contains the concentrations measured at the site for the past 5 years (1996 through 2000).

TABLE 5
Background NO_2 ($\mu g/m^3$) at Fremont-Chapel Way Monitoring
Station for the past three years (maximum is in bold type)

	NO_2
Year	Highest 1-hour average
2003	**143**
2004	113
2005	130

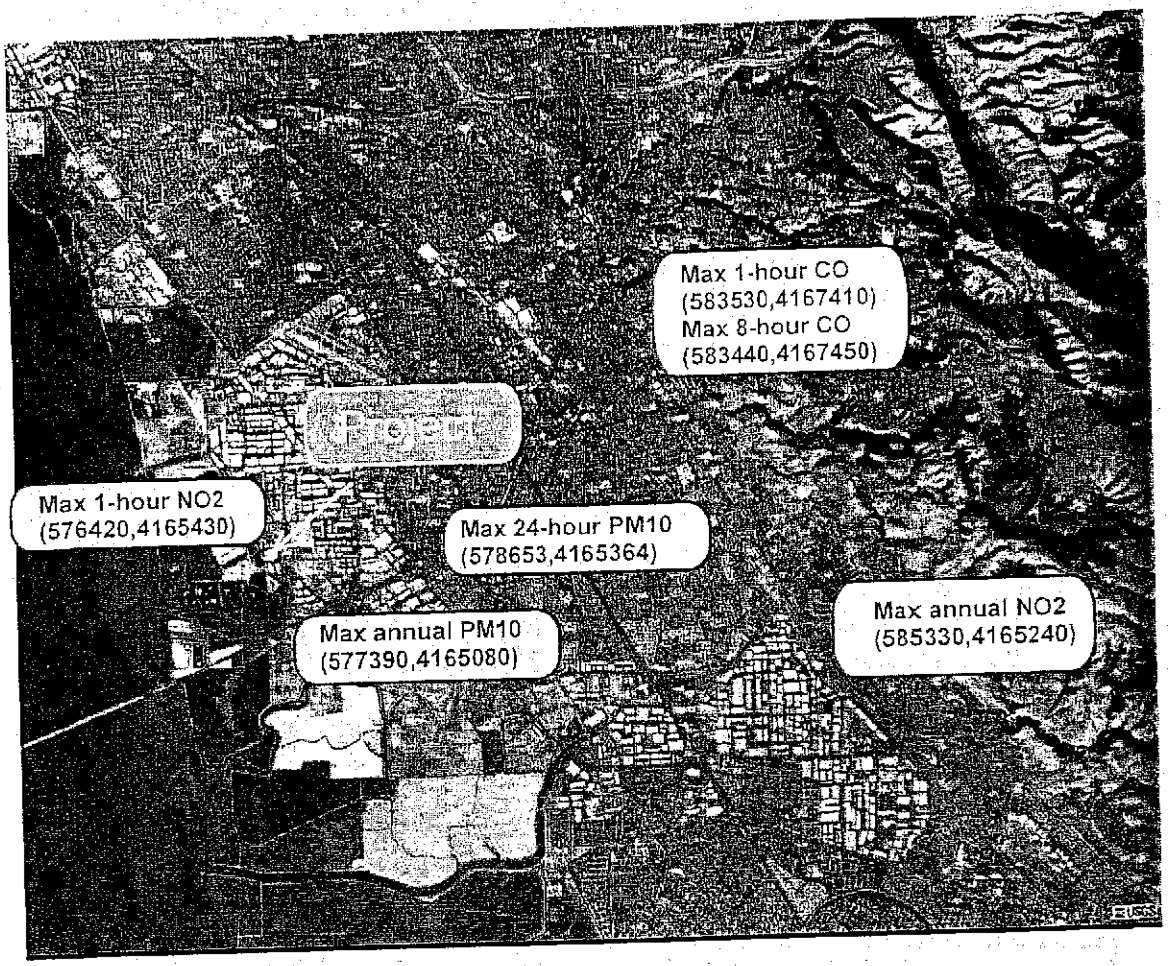

FIGURE 1. Location of project maximum impacts.

Table VI below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. The California ambient NO_2 standard is not exceeded from the proposed project.

TABLE 6
California and national ambient air quality standard and ambient air quality level from the proposed project ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum Impact from Proposed Project	Maximum combined impact plus maximum background	California Standard	National Standard
NO_2	1-hour	143	227	370	470	---

CLASS I PSD INCREMENT ANALYSIS

EPA requires an increment analysis of any PSD source within 100 km of a Class I area which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) inside the Class I area. Point Reyes National Seashore is located roughly 62 km northwest of the project, and is the only Class I area within 100 km of the facility. Shown in Table VII are the results from an impact analysis using ISCST3. The table shows that the maximum 24-hour NO_2 and PM_{10} impacts within the Point Reyes National Seashore are well below the 1 $\mu g/m^3$ significance level (see Table VII)

TABLE 7
Class I 24-hour air quality impacts analysis for the Point Reyes National Seashore ($\mu g/m^3$)

Pollutant	ISCST3	Significance level	Significant
NO_2	0.26	1.0	no
PM_{10}	0.21	1.0	no

VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using both EPA's VISCREEN visibility screening model and the Calpuff model. Both analyses show that the proposed project will not cause any impairment of visibility at Point Reyes National Seashore, the closest Class I area.

The project maximum one-hour average NO_2, including background, is 370 $\mu g/m^3$. This concentration is below the California one-hour average NO_2 standard of 470 $\mu g/m^3$. Crop damage from NO_2 requires exposure to concentrations higher than 470 $\mu g/m^3$ for periods longer than one hour.

Maximum project NO_2, CO, SO_2 and PM_{10} concentrations would be less than all of the applicable national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

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 analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

Appendix F

BACT Cost-Effectiveness Data

ONSITE SYCOM
Energy Corporation

Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines

Contract No. DE-FC02-97CHIO877

Prepared for:

U.S. Department of Energy
Environmental Programs
Chicago Operations Office
9800 South Cass Avenue
Chicago, IL 60439

Prepared by:

ONSITE SYCOM Energy Corporation
701 Palomar Airport Road,
Suite 200
Carlsbad, California 92009

October 15, 1999

TABLE A-5
1999 CONVENTIONAL SCR COST COMPARISON

		Source	5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	161 MW
Direct Capital Costs (DC):					
Purchased Equip. Cost (PE):		MHIA			
Basic Equipment (A):		MHIA	$240,000	$660,000	$2,100,000
Ammonia injection skid and storage	0.00 x A	MHIA	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight	0.08 A x B	OAQPS	$19,015	$52,746	$169,530
PE Total:			$256,704	$712,066	$2,268,849
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$20,536	$56,965	$183,092
Handling and erection:	0.14 x PE	OAQPS	$35,939	$99,889	$320,411
Electrical:	0.04 x PE	OAQPS	$10,268	$28,483	$91,546
Piping:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Insulation:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Painting:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
DI Total:			$77,011	$213,620	$686,595
DC Total:			$333,716	$925,686	$2,975,244
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$25,670	$71,207	$100,000
Construction and field expenses:	0.05 x PE	OAQPS	$12,835	$35,603	$114,432
Contractor fees:	0.10 x PE	OAQPS	$25,670	$71,207	$228,865
Start-up:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Performance testing:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Contingencies:	0.03 x PE	OAQPS	$7,701	$21,362	$68,659
IC Total:			$79,578	$220,741	$580,616
Total Capital Investment (TCI = DC + IC):			$413,294	$1,146,427	$3,555,861
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift; 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift; 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost	OAQPS	$13,125	$13,125	$13,125
Utility Costs:	0% thermal eff; 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr); 1,000 (Btu/ft3) heat value	variable			
Gas cost	3,000 ($/MMcf)				
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$405,720
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/$ft^3$, 7 yr. life	MHIA	$10,352	$56,690	$396,833
Catalyst dispose:	$15/$ft^3$*30 ft^3/MW*MW*.2054 (7 yr amortized)	OAQPS	$388	$2,126	$14,881
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$3,510	$14,820	$108,257
NH_3 inject skid:	.5 (kW) blower; 5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560	$27,720
Total DAC:			$71,219	$180,500	$994,755
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$8,266	$22,929	$71,117
Insurance:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Property tax:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Capital recovery:	10% interest rate, 15 yrs - period; 0.13 x TCI	OAQPS	$52,976	$143,272	$416,329
Total IAC:			$94,314	$213,935	$583,370
Total Annual Cost (DAC + IAC):			$165,533	$394,435	$1,577,125
NO_x Emission Rate (tons/yr) at 42 ppm:			33.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm.	79% removal efficiency		26.4	111.4	813.7
Cost Effectiveness ($/ton):			$6,274	$3,541	$1,938
Electricity Cost Impact (¢/kwh):			0.489	0.204	0.117

*Assume modular SCR is inserted into existing HRSG spool piece

TABLE A-7
1999 SCONOX COST COMPARISON

			5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	170 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		Goalline			
Basic Equipment (A):		Goalline	$620,000	$1,960,000	$7,700,000
Ammonia injection skid and storage	0.00 x A	Goalline	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$49,760	$157,105	$612,238
PE Total:			$671,760	$2,120,916	$8,265,206
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$53,741	$169,673	$661,217
Handling and erection:	0.14 x PE	OAQPS	$94,046	$296,928	$1,157,129
Electrical:	0.04 x PE	OAQPS	$26,870	$84,837	$330,608
Piping:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Insulation:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Painting:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
DI Total:			$201,528	$636,275	$2,479,562
DC Total:			$873,288	$2,757,191	$10,744,770
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Construction and field expenses:	0.05 x PE	OAQPS	$33,588	$106,046	$413,260
Contractor fees:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Start-up:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Performance testing:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Contingencies:	0.03 x PE	OAQPS	$20,153	$63,627	$247,956
IC Total:			$208,246	$657,484	$2,562,214
Total Capital Investment (TCI = DC + IC):			$1,081,534	$3,414,675	$13,306,985
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift; 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift; 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost	OAQPS	$13,125	$13,125	$13,125
Utility Costs:					
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$428,400
Catalyst replace:	** kcfh/MW		$25,880	$106,296	$785,656
Catalyst dispose:	precious metal recovery = 1/3 replace cost	variable	-$8,618	-$35,396	-$261,623
H2 carrier steam	*** lb/hr (93 lb/hr steam/MW @$.006/lb)	variable	$19,686	$107,806	$796,824
H2 reforming	**** CH4 ft3/hr (14ft3/hr/MW @ $.00388/ft3)	variable	$1,916	$10,495	$77,569
H2 skid demand	***** kW (0.6 kW/MW capacity)		$1,270	$6,955	$51,408
Total DAC:			$92,063	$295,458	$1,919,577
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$21,631	$68,293	$266,140
Insurance:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Property tax:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Capital recovery:	10% interest rate; 15 yrs - period; 0.13 x TCI	OAQPS	$138,791	$434,965	$1,646,226
Total IAC:			$205,858	$596,358	$2,203,312
Total Annual Cost (DAC + IAC):			$298,921	$891,816	$4,122,889
NO_x Emission Rate (tons/yr) at 25 ppm:			19.9	83.9	645.9
NO_x Removed (tons/yr) at 2 ppm.	92% removal efficiency		18.3	77.2	594.2
Cost Effectiveness ($/ton):			$16,327	$11,554	$6,938
Electricity Cost Impact (¢/kwh):			0.847	0.462	0.289

* Assume modular SCONOx unit is inserted downstream of HRSG

** 400, 300, 300 kcfh/MW for 5, 25, 150 MW class respectively (s.v.=20kcfh/ft3, $1,500/ft3 catalyst, 7 yr. life)

*** 391, 2139, 15810 lb/hr for 5, 25, 150 MW class respectively

**** 59, 322, 2380 CH4ft3/hr for 5, 25, 150 MW class respectively

***** 3, 14, 102 kW for 5, 25, 150 MW class respectively

REVISED
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

TOWANTIC ENERGY PROJECT

FEBRUARY 2000

R·W·BECK

1998). This value is derived by a formula specified by CTDEP. The Project's maximum emission rate will be 10 ppm, or 43 percent of the allowable MASC limit.

The use of an SCR for NO_x control in combination with an oxidation catalyst for control of CO may increase particulate emissions in the form of ammonium bi-sulfates. Due to the insignificant amount of sulfur in natural gas fuel this impact will be extremely small. During oil-fired operation (the Project will be limited to 720 hours per year of oil-fired operation) the estimated amount of ammonium bi-sulfate emissions will increase particulate emissions by approximately 60 pounds per hour. This increase has only a minor effect on the maximum predicted air quality impacts from the Project, which are well within National Ambient Air Quality Standards.

An environmental benefit of SCR, when combined with a CO Oxidation Catalyst (Section 1.3), is a decrease in emissions of VOCs. Although the Project is not required to include VOCs in the PSD review as discussed in Section 1.1, the use of an SCR and CO Oxidation Catalyst will ensure that VOC emissions are minimal. The reduction in VOC emissions from SCR/CO Oxidation Catalyst is comparable to that from $SCONO_x^{TM}$.

ENERGY ANALYSIS

Use of SCR for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCR reactor. There are other energy requirements associated with chemical transport and operation of equipment, pumps and motors but these are relatively small. Operation of the SCR for the Towantic Project is estimated to reduce electrical output by 1.46 MW or 11,510 MWh of electricity per year[1]. Not only is the electrical output reduced but the fuel use is increased by 135,800 MCF of gas per year.

1.2.4.1.3 ECONOMIC ANALYSIS

Table 3 presents the capital and annualized cost for the SCR control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst), energy penalties and ammonia. All costs are for two GE Frame 7FA gas turbine units, each including one HRSG, which includes the SCR unit.

[1] Based on annual capacity factor of 90%.

issues, poses a serious concern as to whether the Project could secure final construction approval from the Council.

As with the SCR/CO Oxidation Catalyst, $SCONO_x$™ will reduce VOC emissions along with NO_x and CO. The Project is not required to include VOCs in the PSD review, as discussed in Section 1.1, however, $SCONO_x$™ does have the added benefit of decreasing VOC emissions. The reduction in VOC emissions from $SCONO_x$™ is comparable to that from SCR/CO Oxidation Catalyst.

1.2.4.2 .2 ENERGY ANALYSIS

Use of $SCONO_x$™ for NO_x control has an energy penalty due to the energy required to force combustion gases through the $SCONO_x$™ reactor (pressure drop). Pressure drop through the $SCONO_x$™ unit is estimated at 5.25 inches by the manufacturer. This is compared to approximately 3.5 inches of pressure drop for a combined SCR and CO catalyst installed in a HRSG. The pressure drop of 5.25 inches reduces the total plant output by approximately 2.19 MW or 17,266 MWh per year. Not only is the electrical output reduced but the fuel use is increased by 202,200 MCF of gas per year.

Production of the steam used in the regeneration process also imposes a penalty in that the steam is not available to generate electricity. Based on the manufacturer's estimate of low-pressure steam requirements of 15,000 pounds per hour at 600°F and 20 psig, the steam turbine capability of the Project will be reduced by approximately 2.5 MW or 19,710 MWh per year.

The additional energy requirements of the $SCONO_x$™ system (relative to other NO_x control technology) means that the incremental amount of energy will not be supplied by the Project to meet energy needs in the service area. Other power plants will make-up the difference (approximately 4.2 MW) and this will result in a proportional increase in air pollution emissions. These other power plants may emit at levels equal to or greater than the Project.

As with any mechanical system, there are energy requirements associated with the operation of equipment, pumps and motors but these are relatively small. Finally, the $SCONO_x$™ system consumes 200 pounds per hour of natural gas total for regeneration of the catalyst plus leakage. This results in an annual natural gas consumption of 41,800 MCF.

1.2.4.2.3 ECONOMIC ANALYSIS

Table 4 presents the capital and annualized cost for the $SCONO_x$™ control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst) and energy costs. These costs are based on general information provided during a meeting with representatives from ABB Environmental. ABB Environmental was not able to provide a specific cost quote for a $SCONO_x$™ system for a GE 7FA combustion turbine with a HRSG. The projected capital costs are based on a $SCONO_x$™ system designed for an ABB GT-24 unit adjusted for the GE 7FA. The $SCONO_x$™ system also reduces

Exhibit B

EXHIBIT B

Amended
Final
Determination of Compliance

Russell City Energy Center

Bay Area Air Quality Management District
Application 15487

June 19, 2007

Weyman Lee, P.E.
Air Quality Engineer

Table of Contents

I Background

This is the amended Final Determination of Compliance (FDOC) for the Russell City Energy Center (RCEC), a 600-MW, natural-gas fired, combined-cycle merchant power plant proposed by Calpine Corporation (Calpine). The project was originally certified by the California Energy Commission in September, 2002. However, the site has been relocated approximately 1,500 feet to the north from the original location (1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay in the City of Hayward). Hence an amendment to the Authority to Construct is required.

The RCEC will consist of two natural gas fired Westinghouse 501F combustion turbine generators (CTGs), one steam turbine generator (STG) and associated equipment, two supplementally fired heat recovery steam generators (HRSGs), a 9-cell wet cooling tower, and a 300 hp diesel fire pump engine.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the Final Determination of Compliance (FDOC) document for the RCED. It will also serve as the evaluation report for the BAAQMD Authority to Construct application number 15487.

The FDOC describes how the proposed RCEC 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. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, the Preliminary Determination of Compliance (PDOC) has fulfilled the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

II Project Description

1. Permitted Equipment

Calpine is proposing a combined-cycle combustion turbine power generation facility with a nominal electrical output of 600 MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to a steam turbine generator with a rated electrical output of 235 MW.

The RCEC will consist of the following permitted equipment:

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

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

Base Load: Maximum continuous output with duct firing

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 periods 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

The chart below outlines the maximum operating annual air pollutant emissions for this project. The carbon monoxide emissions have decreased from 584.2 tons/year to 389.3 tons/year and the PM_{10} emissions have increased slightly from 86.4 tons/year to 86.8 tons/year. All other emission rates are unchanged from previous application #2896.

NO_2 (ton/yr)	CO (ton/yr)	POC (ton/yr)	PM_{10} (ton/yr)	SO_2 (ton/yr)
134.6	389.3	28.5	86.8	12.2

3. Air Pollution Control Strategies and Equipment

The proposed RCEC 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 and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT level NO_x emission limit of 2 ppmvd @ 15% O_2 (one hour average).

b. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which operate on a lean fuel mixture that minimizes incomplete combustion and CO emissions. The HRSGs will be equipped with low-NO_x duct burners which are also designed to minimize CO emissions. Furthermore, the gas turbines and HRSGs will be abated by oxidation catalysts which will oxidize the CO emissions to produce CO_2 and water. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 4 ppmvd @ 15% O_2 (three hour average).

c. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with low-NO_x burners, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the turbines and HRSGs will be abated by oxidation catalysts which will also reduce POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 1 ppmvd @ 15% O_2 (one hour average).

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

The gas turbines and HRSG duct burners will burn exclusively PUC-regulated natural gas to minimize SO_2 and PM_{10} emissions. Because the SO_2 emission rate is proportional to the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of "low sulfur content" 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.

Table 1 Summary of Control Strategies and Emission Limitations for Gas Turbines and HRSG Duct Burners

Source	Control Strategy and Emission Limit[a]				
	NOx	CO	POC	PM_{10}	SO_2
Gas Turbine & HRSG Power Trains	DLN Combustors/SCR	DLN Combustors/ Oxidation Catalyst	DLN Combustors/ Oxidation Catalyst	PUC-Regulated Natural Gas	PUC-Regulated Natural Gas
	2 ppmv (1 hour average)	4 ppmv (3 hour average)	1 ppmv (1 hour average)	12 lb/hr	6 lb/hr

[a] ppmv concentrations dry at 15% O_2

III 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 2 is a summary of the daily maximum regulated air pollutant emissions for the permitted sources at RCEC. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NPOC, NO_x, SO_2, PM_{10}, or CO are subject to the BACT requirement for that pollutant.

Table 2 Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources (lb/day)					
	Pollutant (lb/day)				
Source	Nitrogen Oxides (as NO_2)	Carbon Monoxide	Precursor Organic Compounds	Particulate Matter (PM_{10})	Sulfur Dioxide
S-1 Gas Turbine & S-2 HRSG[a]	776	5387	148	279	146
S-3 Gas Turbine & S-4 HRSG[a]	776	5387	148	279	146
S-5 Cooling Tower[b]				68	
S-6 Fire Pump Diesel Engine[c]	2.82	0.22	0.21	0.079	0.0033

[a] NOx, CO, and POC emission rates are based upon one 360 minute cold start-up and 18 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day; PM_{10} and SO_2 emission rates are based upon 24 hours of Gas Turbine/HRSG baseload operation at maximum combined firing rate of 2,238.6 MM BTU/hr in one day

[b] emission rates based upon 24 hr/day operation at maximum emission rates; see Appendix B, Section 4.0 for emissions calculations

[c] emission rates based upon 1 hr/day operation at maximum emission rates

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 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-3 SCR Systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Regulation 2, Rule 5.

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions				
Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Turbines/HRSGs				
Acetaldehyde	2.33E+03	6.4E+01		
Acrolein	3.21E+02	2.3E+00	4.03E-02	4.2E-04
Ammonia	1.21E+05	7.7E+03	1.52E+01	7.1E+00
Benzene	2.26E+02	6.4E+00	2.84E-02	2.9E+00
1,3-Butadiene	2.16E+00	1.1E+00		
Ethylbenzene	3.04E+02	7.7E+04		
Formaldehyde	1.56E+04	3.0E+01	1.96E+00	2.1E-01
Hexane	4.40E+03	2.7E+05		
Naphthalene	2.82E+01	1.1E-02		
Total PAHs	1.80E+00	1.1E-02		
Propylene	1.31E+04	1.2E-02		

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions				
Toxic Air Contaminant	Total Project Emissions (lb/yr)	Chronic Trigger Level (lb/yr-project)	Total Project Emissions (lb/hr)	Acute (1 hour max.) Trigger Level (lb/hr)
Propylene Oxide	8.13E+02	4.9E+01	1.02E-01	6.8E+00
Toluene	1.21E+03	1.2E+01	1.51E-01	8.2E+01
Xylenes	4.08E+02	2.7E+04		
Cooling Tower				
Ammonia	1.86E+02	7.7E+03	2.12E-02	7.1E+00
Arsenic	1.55E-01	1.2E-02	1.77E-05	4.2E-04
Cadmium	2.48E-01	4.5E-02		
Hexavalent chromium	1.27E+00	1.3E-03		
Copper	1.88E+00	9.3E+01		
Lead	5.88E-01	5.4E+00	6.71E-05	2.2E-01
Manganese	2.58E+00	7.7E+00		
Mercury	1.86E-03	5.6E-01		
Nickel	1.45E+00	7.3E-01	1.66E-04	1.3E-02
Selenium	2.16E-01	7.7E+02		
Zinc	5.94E+00	1.4E+03		
Firepump Engine				
Diesel Exhaust Particulate	4.0E+00	5.8E-01		

Table 4 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of any of the trigger levels shown must perform modeling to assess the net air quality impact of the proposed facility.

Table 4 Maximum Annual Facility Regulated Air Pollutant Emissions		
Pollutant	*Permitted Source Emissions*[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	134.6	100
Carbon Monoxide	389.3	100
Precursor Organic Compounds	28.5	N/A[d]
Particulate Matter (PM_{10})	86.8	100
Sulfur Dioxide[e]	12.2	100

[a] emission increases from proposed gas turbines and heat recovery steam generators, cooling tower and fire pump diesel engine; specified as permit condition limit

[b] includes start-up and shutdown emissions for gas turbines

[c] for a new major facility

[d] there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal 1-hour ambient air quality standard for ozone

[e] Annual emissions are calculated based on annual average sulfur content of 0.25 grain per 100 scf in natural gas

The sulfuric acid mist (H_2SO_4) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. The applicant has accepted an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established.

IV Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed Russell City Energy Center 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 RCEC 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 2-2-404, "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 the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

Gas Turbines and HRSGs

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners of the proposed RCEC Project. 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 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for NO_x for a combined cycle gas turbine with a rated output $\geq$ 40 MW as 2.0 ppmvd @ 15% O_2 averaged over one hour, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with dry low-NOx combustors. The EPA has accepted this BACT determination as Federal LAER. This BACT determination has been imposed on recent BAAQMD permits issued for : East Altamont Energy Center (Application #2589), and Pico Power Project (Application #6481). In addition, Palomar Energy Project located in San Diego County, a 546 MW combined cycle power plant, recently started up (4/1/06) with a NO_x emission requirement of 2.0 ppmvd, @ 15% O_2, averaged over one hour.

  A NO_x emission concentration of 2.0 ppmvd, @ 15% O_2, averaged over one hour, has been established as "achieved-in-practice" BACT for NO_x based upon our review of CEM data for the ANP Blackstone power plant, a nominal 550-MW combined cycle facility. The ANP Blackstone power plant is located in Blackstone, Massachusetts and consists of two ABB GT-4 Gas Turbines rated at 180-MW each with unfired heat recovery steam generators. We reviewed CEM data for approximately 2,313 firing hours for unit 1 and 2,737 firing hours for unit 2 which occurred from April 2001 to April 2002. With the exception of start-up and shutdown periods, the NOx concentrations were below the 2.0 ppmvd limit by a sufficient margin to demonstrate consistent, continuous compliance.

In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.0 ppmvd NO_x @ 15% O_2, averaged over one hour during all operating modes except gas turbine start-ups and shutdowns. This meets the current District BACT 1 determination and meets or exceeds the current EPA and ARB BACT determinations for NO_x. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. The NO_x emissions from the turbine and HRSG will be abated through the use of a selective catalytic reduction (SCR) system with ammonia injection. The NO_x emission concentration will be verified by a CEM (continuous emissions monitor) located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of less than or equal to 2.0 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

The following "top-down" BACT analysis for NO_x has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. Although this analysis is based upon a controlled NOx emission concentration of 2.5 ppmv instead of the applicable NOx emission rate of 2.0 ppmv, the District has determined that the conclusions of the analysis are applicable to this project.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the RCEC Project. Stone & Webster Management Consultants, Inc. of Denver, Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated and because the selected control technology, SCR, has been demonstrated in practice to achieve NOx emission concentrations of less than 2 ppmv, averaged over one hour, we do not consider $SCONO_x$ to be a viable control alternative for NO_x.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 5 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Table 5 Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	*Average Cost-Effectiveness* ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	*Adverse* Environmental Impacts	Incremental Energy Impact (*MM* BTU/yr)
$SCONO_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a] based upon uncontrolled NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr
[b] based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr
[c] "Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999
[d] does not apply since there is no difference in emission reduction quantity between alternatives
[e] "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 5, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 5, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by

ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15% O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.024 and a chronic hazard index of 0.007 resulting from the emission of all non-carcinogenic compounds, including ammonia, from the gas turbines. In accordance with the District Regulation 2, Rule 5 and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The RCEC will utilize aqueous ammonia in a 19% (by weight) solution. Consequently, the RCEC will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed RCEC facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the RCEC does not justify the elimination of SCR as a control alternative.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER specification for NO_x without causing significant energy, economic, or environmental impacts. Thus, neither can be eliminated as a viable control alternative. The only aspect of this analysis affected by the current NOx BACT standard of 2.0 ppmvd @ 15% O_2, averaged over one hour is the cost of compliance. The increased cost of control for each technology is not expected to affect the conclusion of this analysis. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of two distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only 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.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for CO for combined cycle gas turbines with a rated output of $\geq$ 50 MW as a CO emission concentration of $\leq$ 4.0 ppmvd @ 15% O_2. This BACT specification is based upon the Sacramento Power Authority (Campbell Soup facility) located in Sacramento County, California. BACT 1 (technologically feasible/cost-effective) is currently not specified. This emission rate limit applies to all operating modes except gas turbine start-up and shutdown.

The applicant has agreed to a CO emission limit of 4.0 ppmvd @ 15% O_2, averaged over any rolling 3-hour period. This satisfies the current BACT 2 limitation as discussed above. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. CO emissions from the turbine and HRSG will be abated through the use of an oxidation catalyst. The CO emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

There currently is no BACT 1 (technologically feasible/cost-effective) specification for POC for this source category. Currently, District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for POC for combined cycle gas turbines with an output rating $\geq$ 50 MW as 2 ppmv, dry @ 15% O_2, which is typically achieved through the use of dry-low NOx combustors and/or an oxidation catalyst. This is based upon the Delta Energy Center and Metcalf Energy Center, which were recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

The applicant has proposed to not exceed a POC stack concentration of 1 ppmvd @ 15% O_2 with the use of dry-low NOx combustors and/or an oxidation catalyst. Thus the RCEC satisfies the BACT requirement for POC emissions.

- Heat Recovery Steam Generators (HRSGs)

The HRSG duct burners will be of low-NO_x design, which minimizes incomplete combustion and therefore the POC emission rate. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for SO_2 for combined cycle gas turbines with an output rating of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0028 lb/MM BTU. The proposed turbines will burn exclusively PUC-regulated natural gas with an expected average sulfur content of 0.25 grains per 100 scf, which will result in minimal SO_2 emissions. The annual SO_2 emissions of 12.2 tons are calculated based on the annual average sulfur content. This meets the current BACT 2 specification 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 sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0007 lb/MM BTU. This meets the current BACT 2 specification for SO_2.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT for PM_{10} for combined cycle gas turbines with rated output of ≥ 50 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of ≤ 1.0 grains per 100 scf. The proposed turbines will utilize exclusively PUC-regulated natural gas with an average sulfur content of 0.25 gr/100 scf, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Heat Recovery Steam Generators (HRSGs)

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 ≤ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.25 grains per 100 scf which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Cooling Towers

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

The proposed Cooling Towers will also be equipped with drift eliminators with a drift rate of 0.0005%. This meets BACT for PM_{10}.

Fire Pump Diesel Engine

Based upon 24 hour per day operation under emergency conditions, the proposed fire pump diesel engine triggers BACT for NO_x, POC, and CO, since its potential to emit for each of those pollutants exceeds 10 pounds per day. The current District BACT limits and the specifications for the proposed engine are summarized in Table 6. The applicant will be required by permit conditions to select and install an engine that satisfies BACT for all pollutants listed.

Table 6 District BACT Limits and Proposed Fire Pump Diesel Engine Specifications

Pollutant	District BACT Specifications[a] (g/bhp-hr)	S-6 Engine[b] Specifications (g/bhp-hr)
NOx (as NO_2)	6.9	4.27
CO	2.75	0.33
POC	1.5	0.32
SO_2	Ultra-Low Sulfur Oil	0.005[c]
PM_{10}	Ultra-Low Sulfur Oil	0.12[c]

[a] BACT 2 ("achieved in practice") per District BACT Guideline 96.1.2, "IC Engine – Compression Ignition $\geq$ 175 hp output rating"
[b] emission rates specified by applicant
[c] permit conditions will require the use of ultra-low sulfur oil (15 ppm by weight) at S-6 engine

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NO_x (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NO_x.

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 surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant.

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 RCEC will emit less than 35 tons of POC per year, the POC emissions were offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302.

NO_x Offsets

Because the RCEC will emit greater than 35 tons per year of Nitrogen Oxides (NO_x) from permitted sources, the applicant provided 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 provided POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM$_{10}$ Offsets

Because the total PM$_{10}$ emissions from permitted sources will not exceed 100 tons per year, the RCEC does not trigger the PM$_{10}$ offset requirement of District Regulation 2-2-303.

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 allows for the voluntary offsetting of SO$_2$ emission increases of less than 100 tons per year. The applicant has opted not to provide such emission offsets.

Offset Package

Table 7 summarizes the offset obligation of the RCEC. The emission reduction credits presented in Table 7 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 under the applications cited in the table footnotes. If the quantity of offsets issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated below, Calpine has surrendered valid emission reduction credits to offset the emission increases from the permitted sources proposed for the RCEC project.

Table 7 Emission Reduction Credits Surrendered for RCEC (ton/yr)

Valid Emission Reduction Credits	**POC**	**NO$_x$**
Banking Certificate #, Owner[a]		
602, Calpine	41.0	2.1
687, Calpine	43.8	0.60
688, Calpine	52.3	
855, Calpine		43.5
Total ERC's Identified	137.1	46.2
Permitted Source Emission Limits	28.5	134.6
Offsets Required per BAAQMD Regulations	28.5	154.80
Outstanding Offset Balance	**+108.6[b]**	**-108.6[b]**

[a] These Banking Certificates originated from the following locations:

Certificate	Company	Location	Original Issue Date	Original Cert.
#602	Del Monte Corp	Oakland	6/6/84	#30

#602	Del Monte Corp	Oakland	9/29/87	#82
#602	Del Monte Corp	Oakland	8/1/96	#502
#687	James River Corp	San Leandro	7/20/99	#621
#688	White Cap, Inc	Hayward	7/18/00	#568
#855	PG&E	San Francisco	9/30/85	#14

Certificate #82 was generated by the shutdown of seven soldering machines (S11, 13, 15, 17, 19, 21, & 49) and 2 coating machines (S23 & S24).

Certificate #502 was generated by the shutdown of two ovens (S1 & S2), two coating operations (S3 & S4), cleaning tank (S104), and discontinued use of sealing compounds (S32 through S48).

Certificate #621 was generated by the shutdown of 4 printing presses (S4, 6, 9, & 11), three dryers (S5, 7, & 12), and one boiler (S20).

Certificate #568 was generated by the shutdown of metal decorating applicators (S22, S22, & S33) and cold cleaner (S36).

Certificate #14 was generated by the shutdown of Potrero Units 1&2 (Boilers S-3, S-4, S-5; B&W 500,000 pounds per hour) at the Potrero Power Plant facility.

(Information for certificate #30 is not available)

[b] surplus POC credits used to offset NO_x emission increases per District Regulation 2-2-302.2

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the RCEC 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 RCEC facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards 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. The entire PSD air quality impact analysis is contained in Appendix E.

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. However, RCEC has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions.

Table 8 Maximum Predicted Ambient Impacts of Proposed RCEC ($\mu g/m^3$) [maximums are in bold type]							
Pollutant	Averaging Time	Commissioning Maximum Impact	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	119.2	77	9.5	62.4	**226.8**	19
	annual	—	—	—	—	**0.14**	1.0
CO	1-hour	**1977**	1069	6.5	36.5	134.7	2000
	8-hour	**348**	178	—	—	5.7	500
PM_{10}	24-hour	—	—	2.9	**3.2**	2.94	5
	annual	—	—	—	—	**0.15**	1

Because the maximum modeled project impacts for annual average NO_2, 1-hour & 8-hour average CO, and 24-hour & annual average PM_{10} did not exceed their corresponding significance levels for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded per District regulation 2-2-414 is not required. Table 9 summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed RCEC for the NO_2 1-hour impact that exceeds the significance level. As shown in Table 9, the worst-case NOx emissions from RCEC will not cause or contribute to an exceedance of the California ambient air quality standard for 1-hour NO_2.

Table 9 Applicable California and National Ambient Air Quality Standards (AAQS) and Ambient Air Quality Levels from the Proposed RCEC ($\mu g/m^3$)						
Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	143	227	370	470	---

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the RCEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the RCEC are summarized in Table 2. In accordance with the requirements of the BAAQMD Regulation 2-5 and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing approved air pollutant dispersion models.

Table 10 Health Risk Assessment Results			
Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

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

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 PSD air quality impact analysis insures that the proposed facility will comply with this Regulation by concluding that the Russell City Energy Center will not interfere with the attainment or maintenance of applicable federal or state health-based ambient air quality standards for NO_2, CO and PM_{10}.

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 RCEC has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, S-5 Cooling Tower and S-6 Fire Pump Diesel Engine.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements

As the lead agency under CEQA for the proposed RCEC Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC's CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Final Determination of Compliance (FDOC) serves as the APCO's decision that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC was subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the FDOC is not considered a final determination of whether the facility can be constructed or operated.

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

A risk screening analysis was performed to estimate the health risk resulting from the toxic air contaminant (TAC) emissions from the RCEC. Results from this analysis indicate that the maximally exposed individual cancer risk is estimated at 0.7 in a million, the chronic non-cancer hazard index at 0.007 in a million, and acute non-cancer hazard index at 0.024 in million. Therefore the RCEC will be in compliance the requirements of Regulation 2-5-301. Furthermore, the proposed controls are considered to be toxic best available control technology (TBACT).

Regulation 2, Rule 6: Major Facility Review

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

Regulation 2, Rule 7: Acid Rain

The RCEC gas turbine units and heat recovery steam generators 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), RCEC 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, auxiliary boiler, and emergency generator set 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 (Gas Turbine and HRSG Duct Burners) is 0.0032 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 8,000 mg/l and corresponding maximum PM_{10} emission rate of 2.83 lb/hr, the proposed 9-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 conditions of certification imposed by the California Energy Commission will include requirements for 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 slip emissions from the proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

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

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

Regulation 9: Inorganic Gaseous Pollutants

Regulation 9, Rule 1, Sulfur Dioxide

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

emissions in excess of 300 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines, HRSG duct burners, and firepimp engine are not expected to cause ground level SO_2 concentrations in excess of the limits specified in Regulation 9-1-301 and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations
The proposed combustion gas turbines (each rated at 2038.6 MM BTU/hr, HHV) and HRSG duct burners (each rated at 200 MM BTU/hr, HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.0 ppmvd @ 15% O_2. The proposed fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 2.02 MM BTU/hr, based upon a maximum rated output of 300 bhp.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters
The proposed S-2 & S-4 HRSGs are subject to the emission concentration limits of Regulation 9, Rule 7, section 301 which limits NO_x emissions to 30 ppmv, dry @ 3% O_2 and CO emissions to 400 ppmv, dry @ 3% O_2. To determine if the HRSG duct burners comply with these NO_x emission limits, it would be necessary to install a NOx CEM upstream of the HRSG duct burners since the HRSGs and turbines exhaust through a common stack. Because the combined exhaust from the turbines and HRSGs are subject to a much more stringent BACT limit of 2.0 ppmvd @ 15% O_2, it is reasonable to conclude that the HRSG duct burners comply with the emission limits of Regulation 9, Rule 7. As a practical matter, the HRSG duct burners are therefore subject to Regulation 9, Rule 9.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines
The proposed 300 hp fire pump diesel engine is exempt from Sections 301, 302 and 502 of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The proposed emergency generator will comply with Regulation 9-8-330 which allows emergency use for unlimited hours, and limits non-emergency use to 50 hours per year.

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 2.0 ppmvd @ 15% O_2, they will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: Standards of Performance for New Stationary Sources
Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978", Subpart GG "Standards of Performance for Stationary Gas Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized below:

Source	Requirement	Emission Limitation	Compliance Verification
Gas Turbines and HRSGs	Subpart Da		
	40 CFR 60.44a(a)(1)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 0.0074 lb/NOx/MM BTU
	40 CFR 60.44a(a)(2)	25% reduction of potential NOx emission concentration	SCR Systems will comply with this reduction requirement
	40 CFR 60.44a(d)(1)	1.6 lb NOx/MW-hr	0.055 lb NOx/MW-hr at nominal plant rating of 600 MW
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Sources limited by permit condition to 2.0 ppmv NOx @ 15% O_2, dry
Firepump Diesel Engine	Subpart IIII		
	40 CFR 60	7.8 nmhc+NO_x, 2.6 CO, 0.40 PM_{10} (g/HP-hr) for 2008 and earlier engines	S-6 Firepump Engine will comply with required emission limits. See Table 6.

State Requirements

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

The S-6 Firepump Engine is subject to and will be in compliance with the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines contained in Title 17 of the California Code of Regulations Section 93115. The allowable operating hours and recordkeeping requirements contained in the ATCM will be included in the Permit Conditions.

V 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, shutdown and combustor tuning.

If the CO and NO_x 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_x 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, 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 and/or oxidation catalysts in place. Commissioning activities include, but are not limited to the testing of the gas turbines, adjustment of control systems, and the cleaning of the HRSG steam tubes. Permit conditions 1 through 11 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 applicable short-term ambient air quality standard.

Russell City Energy Center
Permit Conditions

(A) 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 consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Warm and Hot 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 20(b) and 20(d)
Gas Turbine Cold Start-up Mode:	The lesser of the first 360 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 20(b) and 20(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 20(b) through 20(d) until termination of fuel flow to the Gas Turbine

Gas Turbine Combustor Tuning Mode: The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are perfomed, as recommended by the gas turbine manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst are not operating during the tuning operation.

Gas Turbine Cold Start-up: A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown

Gas Turbine Hot Start-up: A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown

Gas Turbine Warm Start-up: A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown

Specified PAHs: The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds

Benzo[a]anthracene
Benzo[b]fluoranthene
Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners), P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems during the commissioning period

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.

Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center

(B) Applicability:

Conditions 1 through 11 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 12 through 49 shall apply after the commissioning period has ended.

A. Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.
2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1 & S-3 Gas Turbines combustors and S-2 & S-4 Heat Recovery Steam Generators duct burners 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, owner/operator shall install, adjust, and operate the A-2 & A-4 Oxidation Catalysts and A-1 & A-3 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.
4. The owner/operator of the RCEC shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 & S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, 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) and HRSGs (S-2 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1 or S-3) sooner than 28 days after the District receives the commissioning plan.
5. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 7, 8, 9, and 10 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), HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.

6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in condition 5 prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.
7. The owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 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 and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
8. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 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 and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
9. 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), Heat Recovery Steam Generators (S-2 & S-4) and S-6 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 23.
10. The owner/ operator shall not operate the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) in a manner such that the combined pollutant emissions from these sources will 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).

NO_x (as NO_2)	4,805 pounds per calendar day	400 pounds per hour

CO	20,000 pounds per calendar day	5,000 pounds per hour
POC (as CH_4)	495 pounds per calendar day	
PM_{10}	432 pounds per calendar day	
SO_2	298 pounds per calendar day	

11. No less than 90 days after startup, the Owner/Operator shall conduct District and CEC approved source tests to determine compliance with the emission limitations specified in condition 19. The source tests 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 and shall include at least one cold start, one warm start, and one hot start. Thirty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of the source testing date.

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

12. The owner/operator shall fire the Gas Turbines (S-1 & S-3) and HRSG Duct Burners (S-2 & S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-4 shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the RCEC. In the event that the rolling 12-month annual average sulfur content exceeds 0.25 grain per 100 standard cubic feet, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions. The reduced annual heat input rate shall be subject to District review and approval. (BACT for SO_2 and PM_{10})
13. The owner/operator shall not operate the units such that 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) exceeds 2,238.6 MM BTU (HHV) per hour. (PSD for NO_x)
14. The owner/operator shall not operate the units such that 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) exceeds 53,726 MM BTU (HHV) per day. (PSD for PM_{10})
15. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) exceeds 35,708,858 MM BTU (HHV) per year. (Offsets)
16. The owner/operator shall not fire the HRSG duct burners (S-2 & S-4) unless its associated Gas Turbine (S-1 & S-3, respectively) is in operation. (BACT for NO_x)
17. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-1 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
18. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-3 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
19. The owner/operator shall ensure that the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (BACT, PSD, and Regulation 2, Rule 5)
    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-1 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-3 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired.

(b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.0 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 and P-2 each shall not exceed 20 pounds per hour or 0.009 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 4.0 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 and P-2 each shall not exceed 5 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-2 and A-4 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2 and A-4 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 29 or District approved alternative method. (Regulation 2-5)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.86 pounds per hour or 0.00128 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 & P-2 each shall not exceed 6.21 pounds per hour or 0.0028 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 8.64 pounds per hour or 0.0042 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 11.64 pounds per hour or 0.0052 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are in operation. (BACT)

20. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up or shutdown does not exceed the limits established below. (PSD, CEC Conditions of Certification)

Pollutant	Cold Start-Up Combustor Tuning lb/start-up	Hot Start-Up lb/start-up	Warm Start-Up lb/start-up	Shutdown lb/shutdown
NO_x (as NO_2)	480.0	125	125	40
CO	5,028	2514	2514	902
POC (as CH_4)	83	35.3	79	16

21. The owner/operator shall not perform combustor tuning on Gas Turbines more than once every rolling 365 day period for each S-1 and S-3. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. (Offsets, Cumulative Emissions)

22. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine,

including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any calendar day:

(a)	1,553 pounds of NO_x (as NO_2) per day	(Cumulative Emissions)
(b)	1,225 pounds of NO_x per day during ozone season from June 1 to September 30.	(CEC Condition of Certification)
(c)	10,774 pounds of CO per day	(PSD)
(d)	295 pounds of POC (as CH_4) per day	(Cumulative Emissions)
(e)	626 pounds of PM_{10} per day	(PSD)
(f)	292 pounds of SO_2 per day	(BACT)

23. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a)	134.6 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b)	389.3 tons of CO per year	(Cumulative Increase, PSD)
(c)	28.5 tons of POC (as CH_4) per year	(Offsets)
(d)	86.8 tons of PM_{10} per year	(Cumulative Increase, PSD)
(e)	12.2 tons of SO_2 per year	(Cumulative Increase, PSD)

24. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1 and P-2 combined to exceed 7 tons in any consecutive 12 month period. (Basis: PSD)

25. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4) combined to exceed the following limits:

formaldehyde	10,912 pounds per year
benzene	226 pounds per year
Specified polycyclic aromatic hydrocarbons (PAHs)	1.8 pounds per year

unless the following requirement is satisfied:

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

26. The owner/operator shall demonstrate compliance with conditions 13 through 16, 19(a) through 19(d), 20, 22(a), 22(b), 23(a) and 23(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_x) concentration, and Carbon Monoxide (CO) concentration at exhaust points P-1 and P-2.

(c) Ammonia injection rate at A-1 and A-3 SCR Systems

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:

(d) Heat Input Rate for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1 and P-2.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 26(d) and 26(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(h) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(i) 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 and all four sources (S-1, S-2, S-3 and S-4) combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined.

(k) on a monthly 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 four sources (S-1, S-2, S-3 and S-4) combined.

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

27. To demonstrate compliance with conditions 19(f), 19(g), 19(h), 22(c), 22(d), 22(e), 23(c), 23(d), 23(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. The owner/operator shall use the actual heat input rates measured pursuant to condition 26, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under condition 30 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:
    (a) For each calendar day, POC, PM_{10}, and SO_2 emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3 & S-4) combined
    (b) on a monthly basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all four sources (S-1, S-2, S-3 & S-4) combined

    (Offsets, PSD, Cumulative Increase)
28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 35,708,858 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1 and S-3 Gas Turbines and/or S-2 and S-4 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (Regulation 2, Rule 5)
29. Within 90 days of start-up of the RCEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 19(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2 or A-4 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with condition 19(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Regulation 2, Rule 5)
30. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to

determine compliance with Conditions 19(a), 19(b), 19(c), 19(d), 19(f), 19(g), and 19(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 19(c) and 19(d), and to verify the accuracy of the continuous emission monitors required in condition 26. 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT, offsets)

31. 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 90 days of start-up of the RCEC and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 25 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	6.4 pounds/year and 2.9 pounds/hour
Formaldehyde	≤	30 pounds/year and 0.21 pounds/hour
Specified PAHs	≤	0.011 pounds/year

(Regulation 2, Rule 5)

33. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 30. If this SAM mass emission limit of condition #24 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

34. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate

compliance with the SAM emission rates specified in condition 24. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (PSD)

35. The owner/operator of the RCEC 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)
36. The owner/operator of the RCEC 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)
37. The owner/operator of the RCEC 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)
38. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 145 feet above grade level at the stack base. (PSD, Regulation 2-5)
39. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)
40. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)
41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)
42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Russell City Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)
43. The owner/operator shall ensure that the Russell City Energy Center complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

c. Hours of operation (emergency).
d. For each emergency, the nature of the emergency condition.
e. Fuel usage for each engine(s).

(Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

VI Recommendation

The APCO has concluded that the proposed Russell City 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 Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst
S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst
S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst
S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst
S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute.
S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 3400 hp, 2.02 MMBtu/hr rated heat input.

Pursuant to District Regulation 2-3-404, this document is subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Russell City Energy Center. The public inspection and comment period will end 30 days after the date of such publication. Written comments on this document should be directed to:

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

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°F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8740 dscf/MM Btu
natural gas higher heating value:	1050 Btu/dscf

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

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

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

Table A-1
Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
Pollutant	lb/MM Btu	lb/hr	lb/MM Btu	lb/hr
Nitrogen Oxides (as NO_2)	0.00735[a]	14.98	0.00735[a]	16.45
Carbon Monoxide	0.0090[b]	18.24	0.0090[b]	19.96
Precursor Organic Compounds	0.00128	2.61	0.00128	2.86
Particulate Matter (PM_{10})	0.00424	8.64	0.0052	11.64
Sulfur Dioxide	0.0028	5.65	0.0028	6.21

[a] based upon stack concentration of 2.0 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 and A-3 Selective Catalytic Reduction Systems with ammonia injection.

[b] based upon the permit condition emission limit of 4 ppmvd CO @ 15% O_2 that reflects abatement by proposed A-2 and A-4 Oxidation Catalysts.

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 2.0 ppmv, dry @ 15% O_2. This emission concentration will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.042 ppmv NO_x, dry @ 0% O_2

($7.042/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8740 dscf/MM Btu)

= 0.00735 lb NO_2/MM Btu

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

(0.00735 lb/MM Btu)(2038.6 MM Btu/hr) = **14.98 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 gas turbine and HRSG and is calculated as follows:

(0.00735 lb/MM Btu)(2238.6 MM Btu/hr) = **16.45 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 4 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(4 ppmv)(20.95 - 0)/(20.95 - 15) = 14.08 ppmv, dry @ 0% O_2

($14.08/10^6$)(lbmol/385.3 dscf)(28 lb CO/lbmol)(8740 dscf/MM Btu)

= 0.0090 lb CO/MM Btu

The CO mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:
(0.0090 lb/MM Btu)(2038.6 MM Btu/hr) = **18.24 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:

(0.0090 lb/MM Btu)(2238.6 MM Btu/hr) = **19.96 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Combustion Gas Turbine

The POC emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled emission limit of 1 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The POC emission factor corresponding to this emission concentration is calculated as follows:

(1 ppmv)(20.95 - 0)/(20.95 - 15) = 3.521 ppmv, dry @ 0% O_2

($3.521/10^6$)(lbmol/385.3 dscf)(16 lb CH_4/lbmol)(8740 dscf/MM Btu)
= **0.00128 lb POC/MM Btu**

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

(0.00128 lb/MM Btu)(2038.6 MM Btu/hr) = **2.61 lb POC/hr**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The POC 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:

(0.00128 lb/MM Btu)(2238.6 MM Btu/hr) = **2.86 lb POC/hr**

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Combustion Gas Turbine and HRSG Combined

The applicant has determined a PM_{10} emission factor of 0.0052 lb/MMBtu at maximum load for the gas turbine and HRSG. It is assumed that this PM_{10} emission factor includes secondary PM_{10} formation of particulate sulfates. The corresponding PM_{10} emission rate is:
(0.0052 lb/MMBtu)/(2238.6 MM Btu/hr) = **11.64 lb/hr**

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

PM_{10} mass emission rate: 11.64 lb/hr
flow rate:4,038,946 lb/hr @ 11.8% O_2 and 180°F
moisture content:8.7% by volume

Converting flow rate to standard conditions:
(4,038,946 lb/hr)(1 hr/60 min)(385.3 cf/lb mol)(1 mol/28.39) = 915,556 acfm
(915,556 acfm)([70 + 460 °R]/[180 + 460 °R])(1 – 0.087) = 692,232 dscfm

Converting to grains/dscf:
(11.64 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(692,232 dscfm) = 0.00196 gr/dscf

Converting to 6% O_2 basis:
(0.00196 gr/dscf)[(20.95 - 6)/(20.95 – 11.8)] = 0.0032 gr/dscf @ 6% O_2

Combustion Gas Turbine

The PM_{10} emission factor is based upon the applicant's assumption of 3 lb/hr for the HRSG PM_{10} emission rate. The corresponding PM_{10} emission factor is therefore:
([11.64-3] lb PM_{10}/hr)/(2038.6 MM Btu/hr) = **0.00424 lb PM_{10}/MM Btu**

SULFUR DIOXIDE EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon maximum natural gas sulfur content of 1.0 grains per 100 scf and a higher heating value of 1050 Btu/scf as specified by PG&E. Although the maximum sulfur content can be as high as 1.0 grain per 100 scf, the actual sulfur content is expected be 0.25 grain per 100 scf, or less on an annual average basis.

The sulfur emission factor is calculated as follows:
(1.0 gr/100scf)(10^6 Btu/MM Btu)(2 lb SO_2/lb S)/[(7000 gr/lb)(1030 Btu/scf)(100 scf)]
= **0.0028 lb SO_2/MM Btu**

The corresponding mass SO_2 emission rate at the maximum combined firing rate of 2238.6 MM Btu/hr is:
(0.0028 lb SO_2/MM Btu)(2238.6 MM Btu/hr) = 6.21 lb/hr

The corresponding SO_2 mass emission rate at the maximum gas turbine firing rate of 2038.6 MM Btu/hr is:
(0.0028 lb SO_2/MM Btu)(2038.6 MM Btu/hr) = 5.65 lb/hr

This is converted to an emission concentration as follows:
(0.0028 lb SO_2/MM Btu)(385.3 dscf/lb-mol)(lb-mol/64.06 lb SO_2)(10^6 Btu/8740 dscf)
= 1.91 ppmvd SO_2 @ 0% O_2

which is equivalent to:
(1.91 ppmvd)(20.95 - 15)/20.95 = 0.54 ppmv SO_2, dry @ 15% O_2

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 and HRSG Duct Burners

Contaminant	**Emission Factor (lb/MM scf)**
Acetaldehyde[d]	6.86E-02
Acrolein	2.37E-02
Ammonia[c]	6.63
Benzene[d]	1.36E-02
1,3-Butadiene[d]	1.27E-04
Ethylbenzene	1.79E-02
Formaldehyde[d]	9.17E-01
Hexane	2.59E-01
Naphthalene	1.66E-03
PAHs[b,d]	1.06E-04
Propylene	7.70E-01
Propylene Oxide[d]	4.78E-02
Toluene	7.10E-02
Xylene	2.61E-02

a California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program, mean values.
b CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.
c based upon maximum allowable ammonia slip of 5 ppmv, dry @ 15% O_2 for A-1 and A-3 SCR Systems
d carcinogenic compound

Table A-3
TAC Emission[a] Factors Cooling Tower

Contaminant	**Emission Factor (ppm)**	**Emission Factor (lb/hr)**
Ammonia	60	2.12E-02
Arsenic	0.05	1.77E-05
Cadmium	0.08	2.83E-05
Chromium (Hex)	0.41	1.45E-04
Copper	0.61	2.15E-04
Lead	0.19	6.71E-05
Manganese	0.84	2.94E-04
Mercury	0.0006	2.12E-07

Table A-3 TAC Emission[a] Factors Cooling Tower		
Nickel	0.47	1.66E-04
Selenium	0.07	2.47E-05
Zinc	1.92	6.78E-04

[a] Based upon maximum drift loss of 353.2 lb/hr and operation of cooling tower at maximum water circulation rate of 141,252 gallons per minute.

AMMONIA EMISSION FACTOR

Combustion Gas Turbine & Heat Recovery Steam Generator

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 5 ppmvd @ 15% O_2.
(5 ppmvd)(20.95 - 0)/(20.95 - 15) = 17.61 ppmv NH_3, dry @ 0% O_2
$(17.61/10^6)$(1 lbmol/385.3 dscf)(17 lb NO_2/lbmol)(8710 dscf/MM Btu) = **0.0068 lb NH_3/MM Btu**

The NH_3 mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:
(0.0068 lb/MM Btu)(2038.6 MM Btu/hr) = **13.80 lb NH_3/hr**

The NH_3 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:
(0.0066 lb/MM Btu)(2238.6 MM Btu/hr) = **15.15 lb NH_3/hr**

Table A-4 Regulated Air Pollutant Emission Factors for Fire Pump Diesel Engine		
	Emission Factor	
Pollutant	g/bhp-hr[a]	lb/hr[b]
Nitrogen Oxides (as NO_2)	4.27	2.82
Carbon Monoxide	0.33	0.22
Precursor Organic Compounds	0.32	0.21
Particulate Matter (PM_{10})	0.12	0.08
Sulfur Dioxide	0.005	0.003

[a] specified by applicant
[b] based upon maximum rated output of 300 bhp

Appendix B

Individual and combined heat input rate limits for the gas turbines, HRSGs, and fire pump engine 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 and S-3 Gas Turbines, each	2,038.6	48,926.4[a]	17,054,433[b]
S-1 CTG and S-2 HRSG, each S-3 CTG and S-4 HRSG, each	2238.6[c]	53,726[d]	17,854,429[e]
S-7 Diesel Engine	2.02	5.1[f]	101[g]

[a] based upon specified maximum rated heat input of 2038.6 MM Btu/hr and 24 hour per day operation
[b] based upon maximum fuel usage of 16,671 MMscf fuel usage per year at 1023 Btu/scf. This is equivalent to 8366 hours per year of operation. (17,054,433 Btu/yr/2038.6 MM Btu/hr)
[c] maximum combined firing rate for gas turbine and HRSG duct burners (200 MM Btu/hr)
[d] based upon maximum duct burner firing of 24 hours per day; calculated as: (24 hr/day)(2,238.6 MM Btu/hr) = 53,726.4 MM Btu/day
[e] based upon maximum duct burner fuel usage of 782.01 MMscf fuel per year usage at 1023 Btu/scf. This is equivalent to 4000 hours per year of HRSG operation. (800,000 Btu/yr/200 MM Btu/hr)
[f] based upon maximum engine operation of 2.5 hours per day (non-emergency); calculated as: (2.5 hr/day)(2.02 MM Btu/hr) = 5.1 MM Btu/day
[g] based upon 52 hours of non-operation operation at full load; calculated as: (50 hr/yr)(2.02 MM Btu/hr) = 101 MM Btu/yr

B-1.0 Gas Turbine Start-Up/Turbine Tuining, and Shutdown Emission Rate Estimates

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound mass emission rates from a gas turbine occur during start-up periods. The PM_{10} and sulfur dioxide emissions are a function only of fuel use rate and do not exceed typical full load emission rates during start-up. The NO_x, CO, and UHC (POC) emission rates shown in Table B-3 are specified by RCEC based upon gas turbine vendor estimates.

Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)						
	Cold Start-Up/Combustor Tuning[a]		**Hot Start-Up[b]**		**Warm Start-Up[c]**	
Pollutant	**lb/hr**	**lb/start-up[g]**	**lb/hr**	**Lb/start-up[g]**	**lb/hr**	**lb/start-up[g]**
NO_x (as NO_2)[f]	97.2	480.0	83.8	125	97.2	125
CO[f]	1348.8	5028	1154.2	2514	1348.2	2514
UHC (as CH_4)[f]	14.9	96	14.9	44.7	14.9	48

Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)						
PM_{10} [d]	10.6	63.6	10.6	31.8	10.6	31.8
SO_x (as SO_2) [e]	2	12	2	6	2	6

[a] cold start not to exceed six hours (360 minutes); by definition, occurs after turbine has been inoperative for at least 72 hours. Combustor tuning not to exceed six hours (360 minutes)

[b] hot start not to exceed 3 hours (180 minutes); by definition, occurs within 8 hours of a shutdown

[c] warm start not to exceed 3 hours (180 minutes); by definition occurs between 8 and 72 hours of a shutdown

[d] as a conservative estimate, based upon full load emission factor of 0.00424 lb PM_{10}/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr

[e] based upon full load emission factor of 0.000693 lb SO_2/MM BTU and maximum heat input rate of 2038.6 MM BTU/hr

[f] maximum hourly emissions for NO_x, CO, and UHC provided by applicant

[g] emissions are not calculated by multiplying hourly rate by number of startup hours for NO_x, CO and UHC. These startup emissions are specified by applicant based on operational data. The startup NO_x emission limit has been adjusted from 240 lb/startup to 125 lb/startup to be consistent with CEC's conditions of certification.

Table B-3 is a comparison of baseload emission rates and shutdown emission rates specified by the applicant.

Table B-3
Gas Turbine Shutdown Emission Rates

Pollutant	Baseload Emission Rate (lb/hr)[a]	Shutdown Emission Rate	
		lb/hr	lb/shutdown[b]
NO_x (as NO_2)	16.45	28.9	40[c]
CO	19.96	224.2	902
UHC (as CH_4)	2.86	6.7	16

[a] emission rates for gas turbine w/duct burner firing

[b] Shutdown not to exceed 30 minutes. Emissions are not calculated by multiplying hourly rate by 0.5 hours for shutdown. These emissions are specified by applicant based on operational data.

[c] The shutdown NO_x emissions limit has been adjusted from 80 lb/shutdown to 40 lb/shutdown to be consistent with CEC's conditions of certification.

B-2.0 Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

The air pollutant emission rates shown in Table B-4 were calculated in Application #2896 (original application for Authority to Construct). RCEC will be subject to the emission rates as the basis of permit condition limits and emission offset requirements. These rates are 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 or shutdowns. Instead, the facility must comply with rolling consecutive twelve-month mass emission limits at all times. The mass emission limits were originally based upon the emission estimates calculated for the following power plant operating envelope.

- 2,800 hours of baseload (100% load) operation per year for each gas turbine
- 5,260 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 27 hot start-ups per gas turbine per year
- 9 warm start-ups per gas turbine per year
- 12 cold start-ups per gas turbine per year

Table B-4:
Maximum Annual Regulated Air Pollutant Emissions for
Gas Turbines HRSGs[a], Natural Gas Engine, Fire Pump Engine, and Cooling Tower

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 Gas Turbines (520 hr/yr of hot start-ups)	41,600	312,693	8,320	4,680	712
S-1 & S-3 Gas Turbines (312 hr/yr of cold start-ups)	24,960	174,304	4,992	2,808	427
S-1 & S-3 Gas Turbines (13,688 total hours[a] @ 100% load)	194,506[b]	234,795[c]	33,809[c]	123,192[c]	18,753[c]
S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs (3000 total hoursa w/duct burner firing and steam injection power augmentation)	46,950[d]	56,660[e]	8,160[e]	36,000[e]	4,530[e]
S-5 Cooling Tower				6,132[f]	
S-6 Diesel Engine[g] (30 hours per year)	117	71	14	4	3
Total Emissions (lb/yr)	308,488	778,523	55,579	172,817	24,426
(ton/yr)	**154.2[h]**	**389.3[i]**	**27.8[j]**	**86.4[k]**	**12.2**

[a] total combined firing hours for both turbines

[b] based upon the heat input rate of 1,979.4 MMBtu/hr for each gas turbine and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2038.6 MMBtu/hr)

[c] based upon the heat input rate of 1,979.4 MM Btu/hr for each gas turbine (heat input rate has been revised to 2038.6 MMBtu/hr)

[d] based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train and annual average NO_2 concentration of 2.0 ppmvd (heat input rate has been revised to 2238.6 MMBtu/hr)

[e] based upon the maximum combined heat input rate of 2,179.4 MM Btu/hr for each CTG/HRSG power train (heat input rate has been revised to 2238.6 MMBtu/hr)

[f] based upon an emission rate of 0.7 lb/hr operated 8760 hr/yr.

Circulation Rate:	135,000 gpm
Drift Rate:	0.0005%
Water Mass Rate:	67,554,000 pph

(135,000 gal/min)(60 min/hr)(8.34 lb/gal)

TDS = 0.7 x 10^6/(67,554,000 x 0.000005) = 2072 ppm (maximum)

(The new cooler tower has a TDS of 8,000 ppm and an emission rate of 24,790 lb PM/yr [2.83 lb/hr X 8760 hr/yr]. The applicant is willing to be subject to maximum facility PM_{10} emissions as previously calculated)

[g] emission rates from vendor guarantee

[h] applicant elected to offset 134.6 tons of NO_x. It is specified by the applicant and is stated to reflect real operating scenarios. Permit conditions will limit total plant NO_x emissions to 134.6 tons per year

[i] adjusted from previous calculation by 4/6 for turbine CO exhaust (new BACT for turbine CO at 4 ppm from 6 ppm)

[j] applicant elected to offset 28.5 tons of POC

[k] PM_{10} emissions increased to 86.8 tons per year

B-3.0Fire Pump Diesel Engine Emissions

Table B-5
Regulated Air Pollutant Emissions for Fire Pump Diesel Engine

Pollutant	Emission Factor		Annual Emissions[a]	
	g/bhp-hr	lb/hr	lb/yr	ton/yr
Nitrogen Oxides (as NO_2)	4.27	2.82	141	0.071
Carbon Monoxide	0.33	0.22	10.9	0.0055
Precursor Organic Compounds	0.32	0.21	10.6	0.0053
Particulate Matter (PM_{10})	0.12	0.079	3.97	0.0020
Sulfur Dioxide	0.005	0.0033	0.165	0.00008

[a] based upon 50 hours of operation per year for testing and maintenance and maximum rated output of 300 bhp

Table B-6
Worst-Case Toxic Air Contaminant Emissions for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Annual Emissions[a] (lb/yr)
Benzene	9.33E-04	0.0942
Toluene	4.09E-04	0.0413
Xylenes	2.85E-04	0.0288
Propylene	2.58E-03	0.2606
1,3-Butadiene	3.91E-05	0.0039
Formaldehyde	1.18E-03	0.1192
Acetaldehyde	7.67E-04	0.0775
Acrolein	9.25E-05	0.0093
Total PAHs	1.68E-04	0.0170
Diesel particulate	3.93E-02	3.97

[a] based upon assumed maximum rated heat input of 2.02 MM BTU/hr and maximum 50 operating hours per year

B-4.0 Cooling Tower PM_{10} Emissions

Cooling tower circulation rate:	141,352 gpm
maximum total dissolved solids:	8000 ppmw
Drift Loss:	353.2 lb/hr

PM_{10} = (8000 ppmw)(353.2 lb/hr)/(10^6)
= 2.83 lb/hr
= 67.8 lb/day (24 hr/day operation)
= 27,790 lb/yr (8,760 operating hours per year)
= 12.4 ton/yr

Drift Rate = (353.2 lb/hr)/(141,352 gal/min)(60 min/hr)(8.33 lb/gal) = 0.0005%

B-5.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs are summarized in **Table B-7.** 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 17,854,429 MM BTU per year for each gas turbine/HRSG power train. The derivation of the emission factors is detailed in Appendix A.

Table B-7
Worst-Case Annual TAC Emissions for Gas Turbines and HRSGs

Toxic Air Contaminant	Emission Factor[a] (lb/MM scf)	lb/yr-power train[b]	ton/yr
Acetaldehyde[c]	1.37E-01	2329	1.16E+00
Acrolein	1.89E-02	321.3	1.61E-01
Ammonia[d]	7.11E+00	120870	6.04E+01
Benzene[c]	1.33E-02	226.1	1.13E-01
1,3-Butadiene[c]	1.27E-04	2.16	1.08E-03
Ethylbenzene	1.79E-02	304.3	1.52E-01
Formaldehyde[c]	9.17E-01	5,456[f]	2.72E+00
Hexane	2.59E-01	4403	2.20E+00
Naphthalene	1.66E-03	28.22	1.41E-02
Propylene	7.71E-01	13107	6.55E+00
Propylene Oxide[c]	4.78E-02	812.6	4.06E-01
Toluene	7.10E-02	1207	6.04E-01
Xylenes	2.40E-02	408	2.04E-01
Total PAHs[e]	1.06E-04	1.8	9.01E-04

[a] CARB CATEF II Database emission factors, mean values
[b] from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4); based upon annual gas usage rate of 17,000MM scf/yr-turbine/HRSG
[c] carcinogenic compounds
[d] based upon the worst-case ammonia slip from the SCR system of 5 ppmvd @ 15% O_2
[e] CARB CATEF II Database does not include an emission factor for PAH. The emission rate from the most recent turbine application is used and reflects abatement by oxidation catalyst.

[f] reflects oxidation catalyst abatement efficiency of 65% (wt) for formaldehyde

The projected toxic air contaminant emissions from S-5 Cooling Tower are summarized in **Table B-8**. The emissions are based upon a water circulation rate of 141,352 gpm and 8,760 hours of operation per year.

Table B-8
Worst-Case TAC Emissions for Cooling Tower

Toxic Air Contaminant	Emission Factor (lb/hr)	Annual Emission Rate (lb/yr)	Annual Emission Rate (ton/yr)
Ammonia	2.12E-02	185.71	9.29E-02
Arsenic	1.77E-05	0.16	7.75E-05
Cadmium	2.83E-05	0.25	1.24E-04
Chromium (Hex)	1.45E-04	1.27	6.35E-04
Copper	2.15E-04	1.88	9.42E-04
Lead	6.71E-05	0.59	2.94E-04
Manganese	2.94E-04	2.58	1.29E-03
Mercury	2.12E-07	0.00	9.29E-07
Nickel	1.66E-04	1.45	7.27E-04
Selenium	2.47E-05	0.22	1.08E-04
Zinc	6.78E-04	5.94	2.97E-03

B-6.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-9**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-9
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]	67.26	194.65	14.24	37.0	6.1
S-3 CTG and S-4 HRSG[a]	67.26	194.65	14.24	37.0	6.1
Sub-Total	**134.52**	**389.3**	**28.48**	**74.0**	**12.2**
S-5 Cooling Towers	0	0	0	12.40	0
S-6 Diesel Fire Pump Engine	0.071	0.0055	0.0053	0.002	0.00008
Total Facility Emissions	**134.6**	**389.3**	**28.5**	**86.4**	**12.2**

[a] includes gas turbine start-up/combustor tuning and shutdown emissions

Table B-10 Baseload Air Pollutant Emission Rates for Gas Turbines and HRSGs (Excluding Gas Turbine Start-up and Shutdown Emissions)					
	NO_2	CO	POC	PM_{10}	SO_2
Each Gas Turbine (2038.6 MM BTU/hr)					
lb/hr-source	14.98	18.24	2.61	8.64	6.21
lb/day-source	360	438	63	207	149
Each Gas Turbine/HRSG Power Train (2,238.6 MM BTU/hr and 24 hour per day duct burner firing					
lb/hr-power train	16.45	19.96	2.86	11.64	5.65
lb/day-power train	395	479	69	279	136

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-11**.

Table B-11 Maximum Daily Regulated Air Pollutant Emissions per Power Train (lb/day)					
Source (operating mode)	**NO_2**	**CO**	**POC**	**PM_{10}**	**SO_2**
Gas Turbine (6-hr cold start-up)	480	5028	96	63.6	34
Gas Turbine & HRSG (18 hours full load w/duct burner firing)	296.1	359.3	51.5	215.4	112
Total	**776**	**5387**	**148**	**279**	**146**

Table B-12 summarizes the worst-case daily regulated air pollutant emissions from permitted sources. These are the basis of permit condition daily mass emission limits. The operating scenario assumes simultaneous cold start-up of two gas turbines followed by 18 hours of full load operation with duct burner firing. Cooling tower operates 24 hours per day and the fire pump diesel engine operates for a maximum of 0.5 hours per day for exercising.

Table B-12 Worst-Case Daily Regulated Air Pollutant Facility Emissions from Permitted Sources (lb/day)					
Source (Operating Mode)	**NO_2**	**CO**	**POC**	**PM_{10}**	**SO_2**
Two Gas Turbines (6-hr cold start-up)	960	10,056	192	127.2	68
Two Gas Turbine/HRSG Power Trains (18 hours @ full load w/Duct Burner Firing)	592.2	718.6	103	430.8	224
Gas Turbine/HRSG Powertrain Sub-total	**1552**	**10,774**	**295**	**558**	**292**
S-5 Cooling Tower				68	
S-6 Diesel Fire Pump Engine	1.41	0.11	0.11	0.0017	0.04
Total	**1,553**	**10,774**	**295**	**626**	**292**

[a] daily maximum for these pollutants occur when all four turbines are operating at full load w/duct burner firing

B-7.0 Maximum Facility Emissions During Commissioning Period

Table B-13 summarizes the worst-case 1-hour and 8-hour emission rates for the RCEC during the commissioning period, when the SCR systems and oxidation catalysts are not yet installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the RCEC 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-13
Worst-Case Short-Term NO2 and CO Emission Rates for Gas Turbines during Commissioning Perioda

	NO_2	CO	POC	PM_{10}	SO_2
Both Gas Turbines	400 lb/hr	5,000 lb/hr			
Both Gas Turbines	4,805 lb/day	20,000 lb/day	495 lb/day	432 lb/day	297.6 lb/day

[a] data provide by applicant based upon data collected at the Calpine Metcalf Energy Center

B-8.0 Modeling Emission Rates

The emission rates shown in **Table B-14** were used to model the air quality impacts of the RCEC to determine compliance with State and Federal annual ambient air quality standards for NO_2, CO, and PM_{10}. A screening impact analysis of two gas turbine/HRSG duct burner systems, a 9-cell cooling tower, and a diesel fire pump engine emission rates and stack gas characteristics revealed that the worst-case impacts occur under the equipment operating scenarios listed.

TABLE B-14

Averaging Period Emission Rates Used in Modeling Analysis (g/s)

Pollutant Source	Max. (1-hour)	Commissioning[a] (1-hour)	Start-up[b] (1-hour)	Start-up[b] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[a] Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time.

[b] Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Appendix C

Emission Offsets

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required for permitted sources. Emission offsets have been provided for NO_x and POC emission increases associated with S-1 Gas Turbine, S-2 HRSG, S-3 Gas Turbine, S-4 HRSG, S-5 Cooling Tower, and S-6 Diesel Engine.

Table C-1
Emission Offset Summary

	NO_2	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	134.6	389.3	28.5	86.4	12.2
Offset Requirement Triggered	Yes	N/A	Yes	No	No
Offset Ratio	1.15[b]	N/A	1.00[c]	N/A	N/A
Offsets Required (tons)	**154.8**	**0**	**28.5**	**0**	**0**

[a]Sum of emission increases from all permitted sources.

[b]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 emissions from permitted sources will exceed 35 tons per year.

[c]Pursuant to District Regulation 2-2-302, an offset ratio of 1.0 applies since the facility POC emissions are less than 35 tons per year.

Appendix D

Health Risk Assessment

As a result of: (1) combustion of natural gas at the proposed Gas Turbines and HRSGs (2) diesel fired fire pump engine and (3) the presence of dissolved solids in the cooling tower water, the proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 2, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, 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) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70 year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, 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. The worst-case assumption is made that the exposure occurs over a one-year period. Per the BAAQMD Regulation 2-5, a project with a total chronic and acute hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table D-1**.

Table D-1 Health Risk Assessment Results			
Receptor	Cancer Risk (risk in one million)	Chronic Non-Cancer Hazard Index (risk in one million)	Acute Non-Cancer Hazard Index (risk in one million)
Maximally Exposed Individual	0.7	0.007	0.024
Resident	≤ 0.7	≤ 0.007	≤ 0.024
Worker	≤ 0.7	≤ 0.007	≤ 0.024

In accordance with the BAAQMD Regulation 2-5, the increased carcinogenic risk, chronic hazard index, and acute hazard index attributed to this project are each considered to be not significant since they are each less than 1.0.

Based upon the results given in Table D-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER

February 7, 2007

BACKGROUND

Russell City Energy Center LLC has submitted a permit application (# 15487) for a proposed 600 MW combined cycle power plant, the Russell City Energy Center (RCEC). The facility is to consist of two natural gas-fired turbines with supplementary fired heat recovery steam generators, one steam turbine and supplemental burners (duct burners), a 9-cell cooling tower, and a diesel fire pump engine. The proposed 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 I, along with the corresponding significant emission rates for air quality impact analysis.

TABLE 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 to 2-2-306)	EPA PSD Significant Emission Rates for major stationary sources (tons/year)
NO_x	134.6	100	40
CO	584.2	100	100
PM_{10}	86.8	100	15
SO_2	12.2	100	40

Table I indicates that the proposed project emissions exceed District significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), and respirable particulate matter (PM_{10}). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table I). Table I shows that the NO_2, CO and PM_{10} ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in Sections

304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

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 impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_2, 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, impacts due to inversion breakup fumigation, and impacts due to shoreline fumigation.

Emissions from the turbines and burners will be exhausted from two 145 foot exhaust stacks and the fire pump will be exhausted from a 15 foot exhaust stack. Emissions from a 9-cell cooling tower will be released at a height of 60 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, turbine startup, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Startup conditions were modeled with one turbine in startup mode, while the other turbine was in normal operation.

The EPA models SCREEN3 and ISCST3 were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using five years of meteorological data (1990 through 1994) collected approximately 6.6 km southeast of the project at the BAAQMD's Union City meteorological monitoring station. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Using 1990-1994 San Leandro ozone monitoring data, the Ozone Limiting Method was employed to convert one-hour NO_x impacts into one-hour NO_2 impacts. (The San Leandro monitoring station is located 8.8 km north of the project) The Ambient Ratio Methodology (with a default NO_2/NO_x ratio of 0.75) was used for determining the annual-averaged NO_2 concentrations. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation and shoreline fumigation were evaluated using the SCREEN3 model.

TABLE 2
Averaging period emission rates used in modeling analysis (g/s)

Pollutant Source	Max. (1-hour)	Commis-sioning[1] (1-hour)	Start-up[2] (1-hour)	Start-up[2] (8-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average
NO_x							
Turbine/Duct Burner 1	2.04	48.36	12.25	—	—	—	1.94
Turbine/Duct Burner 2	2.04	2.04	12.25	—	—	—	1.94
Fire Pump	0.36	—	—	—	—	—	0.00211
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
CO							
Turbine/Duct Burner 1	2.48	627.47	169.95	80.24	1.34	—	—
Turbine/Duct Burner 2	2.48	2.48	169.95	80.24	1.34	—	—
Fire Pump	0.0275	—	—	—	0.0034	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—	—
PM_{10}							
Turbine/Duct Burner 1	—	—	—	—	—	1.134	1.07
Turbine/Duct Burner 2	—	—	—	—	—	1.134	1.07
Fire Pump	—	—	—	—	—	0.000417	0.0000594
Each Cooling Tower Cell (9 total))	—	—	—	—	—	0.0396	0.0387

[1]Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation. Both turbines will not be commissioned at the same time. [2]Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

Also shown in Table III are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table III shows that the only impact requiring further analysis is the 1-hour NO_2 modeled impact.

TABLE 3
Maximum predicted ambient impacts of proposed project ($\mu g/m^3$)
[maximums are in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	119.2	77	9.5	62.4	**226.8**	19
	annual	—	—	—	—	**0.14**	1.0
CO	1-hour	**1977**	1069	6.5	36.5	134.7	2000
	8-hour	**348**	178	—	—	5.7	500
PM_{10}	24-hour	—	—	2.9	**3.2**	2.94	5
	annual	—	—	—	—	**0.15**	1

Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," 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 IV lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, the modeled NO2 impact is well below the preconstruction monitoring threshold.

TABLE 4
PSD monitoring exemption level and maximum impact from the proposed project for NO_2 ($\mu g/m^3$)

Pollutant	Averaging Time	Exemption Level	Maximum Impact from Proposed Project
NO_2	annual	14	0.14

The District-operated Fremont-Chapel Way Monitoring Station, located 18.3 km southeast of the project, was chosen as representative of background NO_2 concentrations. Table V contains the concentrations measured at the site for the past 5 years (1996 through 2000).

TABLE 5 Background NO_2 ($\mu g/m^3$) at Fremont-Chapel Way Monitoring Station for the past three years (maximum is in bold type)	
	NO_2
Year	Highest 1-hour average
2003 2004 2005	**143** 113 130

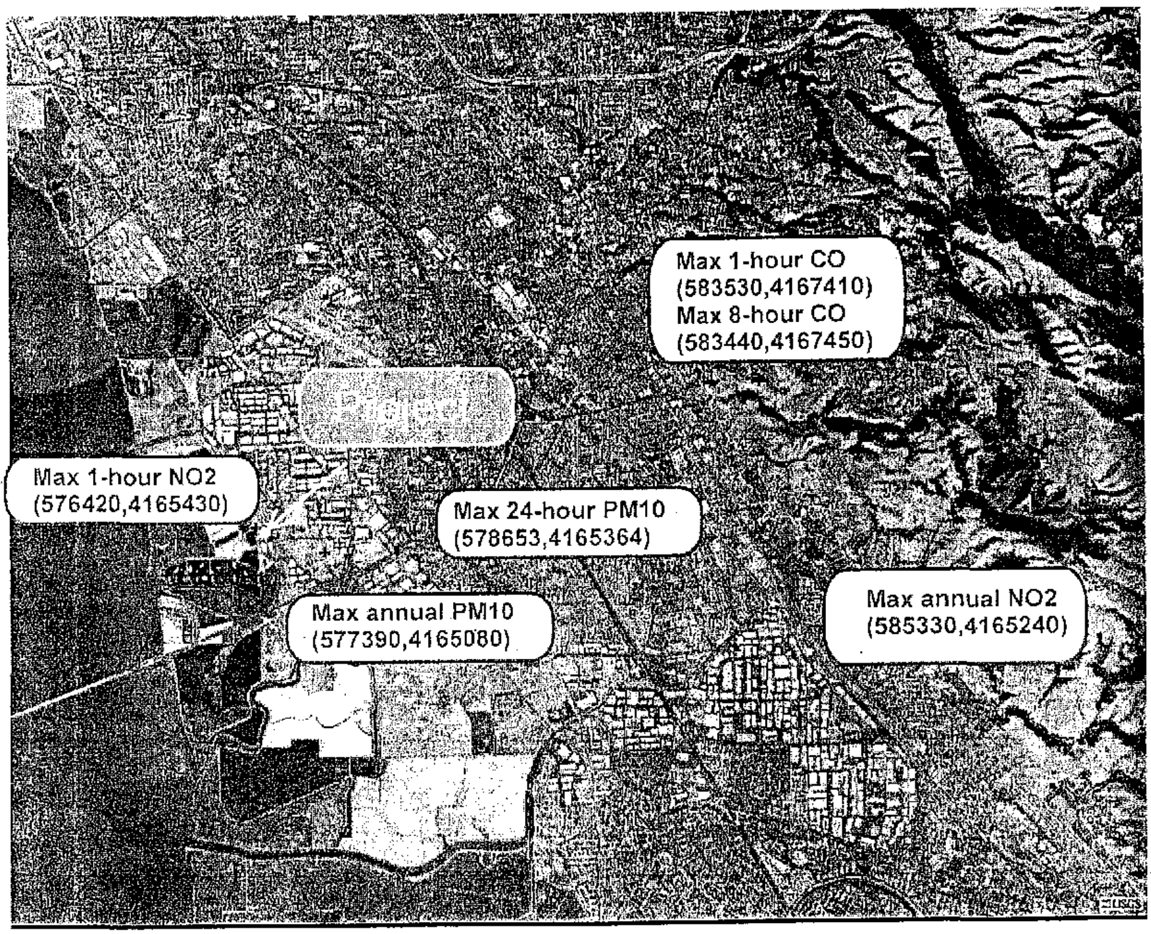

FIGURE 1. Location of project maximum impacts.

Table VI below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. The California ambient NO_2 standard is not exceeded from the proposed project.

TABLE 6
California and national ambient air quality standard and ambient air quality level from the proposed project ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum Impact from Proposed Project	Maximum combined impact plus maximum background	California Standard	National Standard
NO_2	1-hour	143	227	370	470	---

CLASS I PSD INCREMENT ANALYSIS

EPA requires an increment analysis of any PSD source within 100 km of a Class I area which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) inside the Class I area. Point Reyes National Seashore is located roughly 62 km northwest of the project, and is the only Class I area within 100 km of the facility. Shown in Table VII are the results from an impact analysis using ISCST3. The table shows that the maximum 24-hour NO_2 and PM_{10} impacts within the Point Reyes National Seashore are well below the 1 $\mu g/m^3$ significance level (see Table VII)

TABLE 7
Class I 24-hour air quality impacts analysis for the Point Reyes National Seashore ($\mu g/m^3$)

Pollutant	ISCST3	Significance level	Significant
NO_2	0.26	1.0	no
PM_{10}	0.21	1.0	no

VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using both EPA's VISCREEN visibility screening model and the Calpuff model. Both analyses show that the proposed project will not cause any impairment of visibility at Point Reyes National Seashore, the closest Class I area.

The project maximum one-hour average NO_2, including background, is 370 $\mu g/m^3$. This concentration is below the California one-hour average NO_2 standard of 470 $\mu g/m^3$. Crop damage from NO_2 requires exposure to concentrations higher than 470 $\mu g/m^3$ for periods longer than one hour.

Maximum project NO_2, CO, SO_2 and PM_{10} concentrations would be less than all of the applicable national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

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 analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

Appendix F

BACT Cost-Effectiveness Data

ONSITE SYCOM

Energy Corporation

Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines

Contract No. DE-FC02-97CHIO877

Prepared for:

U.S. Department of Energy
Environmental Programs
Chicago Operations Office
9800 South Cass Avenue
Chicago, IL 60439

Prepared by:

ONSITE SYCOM Energy Corporation
701 Palomar Airport Road,
Suite 200
Carlsbad, California 92009

October 15, 1999

TABLE A-5
1999 CONVENTIONAL SCR COST COMPARISON

	Basis	Source	5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	161 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		MHIA			
Basic Equipment (A):		MHIA	$240,000	$660,000	$2,100,000
Ammonia injection skid and storage	0.00 x A	MHIA	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$18,015	$52,746	$169,530
PE Total:			$258,704	$712,066	$2,288,649
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$20,536	$56,965	$183,092
Handling and erection:	0.14 x PE	OAQPS	$35,939	$99,689	$320,411
Electrical:	0.04 x PE	OAQPS	$10,268	$28,483	$91,546
Piping:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Insulation:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Painting:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
DI Total:			$77,011	$213,620	$686,595
DC Total:			$333,716	$925,686	$2,975,244
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$25,670	$71,207	$100,000
Construction and field expenses:	0.05 x PE	OAQPS	$12,835	$35,603	$114,432
Contractor fees:	0.10 x PE	OAQPS	$25,670	$71,207	$228,865
Start-up:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Performance testing:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Contingencies:	0.03 x PE	OAQPS	$7,701	$21,362	$68,659
IC Total:			$79,578	$220,741	$580,616
Total Capital Investment (TCI = DC + IC):			$413,294	$1,146,427	$3,555,861
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift; 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift; 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost	OAQPS	$13,125	$13,125	$13,125
Utility Costs:	0% thermal eff; 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr); 1,000 (Btu/ft3) heat value				
Gas cost	3,000 ($/MMcf)	variable			
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$405,720
Catalyst replace:	assume 30 ft³ catalyst per MW, $400/ft³, 7 yr. life	MHIA	$10,352	$56,690	$396,833
Catalyst dispose:	$15/ft³*30 ft³/MW*MW*.2064 (7 yr amortized)	OAQPS	$388	$2,126	$14,881
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$3,510	$14,820	$108,257
NH_3 inject skid:	5 (kW) blower; 5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560	$27,720
Total DAC:			$71,219	$180,500	$994,755
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$8,266	$22,929	$71,117
Insurance:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Property tax:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Capital recovery:	10% interest rate, 15 yrs - period; 0.13 x TCI	OAQPS	$52,976	$143,272	$415,329
Total IAC:			$94,314	$213,935	$582,370
Total Annual Cost (DAC + IAC):			$165,533	$394,435	$1,577,125
NO_x Emission Rate (tons/yr) at 42 ppm:			33.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm,	79% removal efficiency		26.4	111.4	813.7
Cost Effectiveness ($/ton):			$6,274	$3,541	$1,938
Electricity Cost Impact (¢/kwh):			0.469	0.204	0.117

*Assume modular SCR is inserted into existing HRSG spool piece issues, poses a serious concern as to whether the Project could secure final construction approval from the Council.

As with the SCR/CO Oxidation Catalyst, SCONO$_x$™ will reduce VOC emissions along with NO_x and CO. The Project is not required to include VOCs in the PSD review, as discussed in Section 1.1, however, SCONO$_x$™ does have the added benefit of decreasing VOC emissions. The reduction in VOC emissions from SCONO$_x$™ is comparable to that from SCR/CO Oxidation Catalyst.

1.2.4.2 .2 ENERGY ANALYSIS

Use of SCONO$_x$™ for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCONO$_x$™ reactor (pressure drop). Pressure drop through the SCONO$_x$™ unit is estimated at 5.25 inches by the manufacturer. This is compared to approximately 3.5 inches of pressure drop for a combined SCR and CO catalyst installed in a HRSG. The pressure drop of 5.25 inches reduces the total plant output by approximately 2.19 MW or 17,266 MWh per year. Not only is the electrical output reduced but the fuel use is increased by 202,200 MCF of gas per year.

Production of the steam used in the regeneration process also imposes a penalty in that the steam is not available to generate electricity. Based on the manufacturer's estimate of low-pressure steam requirements of 15,000 pounds per hour at 600°F and 20 psig, the steam turbine capability of the Project will be reduced by approximately 2.5 MW or 19,710 MWh per year.

The additional energy requirements of the SCONO$_x$™ system (relative to other NO_x control technology) means that the incremental amount of energy will not be supplied by the Project to meet energy needs in the service area. Other power plants will make-up the difference (approximately 4.2 MW) and this will result in a proportional increase in air pollution emissions. These other power plants may emit at levels equal to or greater than the Project.

As with any mechanical system, there are energy requirements associated with the operation of equipment, pumps and motors but these are relatively small. Finally, the SCONO$_x$™ system consumes 200 pounds per hour of natural gas total for regeneration of the catalyst plus leakage. This results in an annual natural gas consumption of 41,800 MCF.

1.2.4.2.3 ECONOMIC ANALYSIS

Table 4 presents the capital and annualized cost for the SCONO$_x$™ control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst) and energy costs. These costs are based on general information provided during a meeting with representatives from ABB Environmental. ABB Environmental was not able to provide a specific cost quote for a SCONO$_x$™ system for a GE 7FA combustion turbine with a HRSG. The projected capital costs are based on a SCONO$_x$™ system designed for an ABB CT-24 unit adjusted for the GE 7FA. The SCONO$_x$™ system also reduces