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

In re: Russell City Energy Center PSD Permit No. 15487	PSD Appeal Nos. 10-02; 10-03; 10-04; 10-08; 10-09; 10-10

RUSSELL CITY ENERGY COMPANY, LLC'S CONSOLIDATED EXHIBITS TO ITS RESPONSES TO PETITIONS FOR REVIEW FILED BY:

CHABOT-LAS POSITAS COMMUNITY COLLEGE DISTRICT
(PSD APPEAL 10-02)

CITIZENS AGAINST POLLUTION
(PSD APPEAL 10-03)

ROBERT SARVEY
(PSD APPEAL 10-04)

HAYWARD AREA RECREATION AND PARK DISTRICT
(PSD APPEAL NO. 10-08)

MINANE JAMESON
(PSD APPEAL NO. 10-09)

IDOJINE J. MILLER
(PSD APPEAL NO. 10-10)

VOLUME 1 OF 2

Kevin Poloncarz
Holly L. Pearson
Bingham McCutchen LLP
Three Embarcadero Center
San Francisco, CA 94111
Telephone: (415) 393-2870
Facsimile: (415) 262-9201
Email: kevin.poloncarz@bingham.com

Attorneys for Russell City Energy Company, LLC

RUSSELL CITY ENERGY COMPANY, LLC'S
CONSOLIDATED EXHIBITS TO ITS
RESPONSES TO PETITIONS FOR REVIEW
(PSD APPEAL NOS. 10-02; 10-03; 10-04; 10-08; 10-09; 10-10)

EXHIBIT INDEX

**RUSSELL CITY ENERGY COMPANY, LLC'S
CONSOLIDATED EXHIBITS TO ITS
RESPONSES TO PETITIONS FOR REVIEW
(PSD APPEAL NOS. 10-02; 10-03; 10-04; 10-08; 10-09; 10-10)**

EXHIBIT INDEX

Exhibit 1

Statement of Basis
for
Draft Amended Federal "Prevention of Significant Deterioration" Permit

Russell City Energy Center

Bay Area Air Quality Management District

Application Number 15487

December 8, 2008

Prepared by
Weyman Lee, P.E.
Senior Air Quality Engineer

Table of Contents

I. INTRODUCTION

The Bay Area Air Quality Management District ("Air District") is proposing to issue an amended Prevention of Significant Deterioration Permit ("Federal PSD Permit") for the Russell City Energy Center. The Russell City Energy Center, described in detail in subsequent sections of this document, is a proposed 600 megawatt natural gas fired combined-cycle power plant, proposed to be built near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. The Air District is issuing a draft of an amended Federal PSD permit for the project, and is providing an opportunity for the public to review and comment on the draft prior to the District's final decision on the permit. This document is the Air District's Statement of Basis for the proposed permit.

This Statement of Basis has been prepared in accordance with Sections 124.7 and 124.8 of Title 40 of the Code of Federal Regulations, which set forth the procedural requirements for issuing Federal PSD Permits. The purpose of this Statement of Basis is to briefly set forth the principal facts and the significant factual, legal, methodological and policy questions that the Air District has considered in preparing the draft permit, and to briefly describe the derivation of the draft permit conditions and the reasons for them.[1] The Statement of Basis documents the Air District's proposed decision to issue the Federal PSD Permit in order to provide the public an opportunity to comment on it.

Following this Introduction, Section II outlines the legal framework for Federal PSD Permits and other environmental permitting requirements for power plants, such as the proposed Russell City Energy Center. This section describes the permitting action that the Air District is proposing in the context of the other permits and approvals that have been granted for the project, including the California Energy Commission's license for the project. Section II also discusses how the public can participate in the permitting process and provide input to the Air District on the current proposal.

Sections III and IV provide a detailed description of the proposed Russell City Energy Center project and the air emissions that the project would entail. Section III provides an overview of the power plant and explains what equipment would be installed and how it would operate. Section IV describes the maximum air pollutant amounts that the project would emit, and explains which emissions are subject to the Federal PSD Regulations.

Sections V and VI then describe how the Federal PSD Permit requirements apply to the project. Section V discusses the "Best Available Control Technology" requirements and how they apply to the equipment at the proposed facility. Section VI follows with a discussion of the Air Quality

[1] 40 C.F.R. sections 124.7 and 124.8 require that a Federal PSD permitting agency prepare either a "statement of basis" or a "fact sheet" to document its permitting decisions. The Air District normally uses the term "statement of basis" to refer to a more comprehensive document than a "fact sheet", which the Air District usually considers to be a brief overview rather than a detailed statement of reasons underlying a permitting decision. Given the Air District's historical practice regarding these terms, the Air District has titled this document a "Statement of Basis" for the permit, even though the Federal PSD regulations appear to contemplate that a document called a "fact sheet" should be more detailed and comprehensive than a "statement of basis". These semantic issues notwithstanding, the Air District considers this document to be its full explanation of its proposed permitting decision and the reasons for it, and intends it to satisfy all of the requirements in 40 C.F.R. sections 124.7 and 124.8. The Air District is also issuing a separate, shorter document entitled "fact sheet" to provide the public with a brief overview of the important aspects of the project. That "fact sheet" is not intended to discuss all the detailed information required by 40 C.F.R. section 124 provided in this document.

Impact Analyses that the Air District has conducted for the proposed facility as required by the Federal PSD Regulations.

Section VII then notes some additional legal requirements outside of the Federal PSD Permit program that are applicable to this project, including environmental justice concerns. Section VIII sets forth the proposed permit conditions for the facility. Section IX concludes with the Air District's proposal to issue a Federal PSD Permit for the project.

The Air District encourages all interested members of the public to review this document and learn about the project and the proposed amended Federal PSD Permit. The Air District also invites all interested members of the public to comment on any aspect of the proposal to issue the permit. Comments on the permit may be submitted to the District in writing or in person at the public hearing (*see* Section II below for more information).

II. LEGAL FRAMEWORK FOR PSD PERMITTING and OPPORTUNITIES FOR PUBLIC PARTICIPATION

Power plant permitting in California involves various state and federal agencies and multiple overlapping regulatory requirements, including the Federal PSD Permit requirements. This section provides background information on the permitting process and the regulatory requirements for issuing a Federal PSD Permit, as well as the public participation process.

A. POWER PLANT PERMITTING IN CALIFORNIA

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

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

The Air District collaborates with the Energy Commission regarding the air quality portion of its environmental analysis and prepares a "Determination of Compliance" that outlines whether and how the proposed project will comply with applicable air quality regulatory requirements. The Determination of Compliance is used by the Energy Commission to assess air quality issues of the proposed power plant.

The Air District also takes two important permitting actions that complement the Energy Commission's license. First, although the Warren-Alquist Act supersedes all other *state-law* permitting requirements, under the Constitution a state legislature cannot preempt federal law. For this reason, the Warren-Alquist Act cannot override federal permit requirements under the Clean Air Act, including the Federal PSD Permit requirement under Clean Air Act Section 165 and U.S. Environmental Protection Agency ("EPA") regulations in Section 52.21 of Title 40 of the Code of Federal Regulations. Proposed power plant projects must obtain Federal PSD Permits (if they are large enough to be subject to the Federal PSD Permit program) issued under EPA's jurisdiction pursuant to the Clean Air Act and its implementing regulations, notwithstanding the state-law CEC licensing process. EPA has delegated federal PSD permitting authority to the Air District for projects in the San Francisco Bay Area. (*See* U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21, (February 6,

2008) ("Delegation Agreement").) A proposed power plant projects must therefore obtain a Federal PSD Permit from the Air District as a requirement of federal law, in addition to the CEC license.

Second, once the Energy Commission grants a license for a power plant, the Air District incorporates the conditions of certification addressing air quality issues into an Authority to Construct permit. (*See* District Regulation 2-3-405.) The District needs to incorporate the conditions of certification into a District permit to make them enforceable by District inspectors, as only permit conditions in District-issued permits and not in CEC-issued licenses can be enforced by the District. (*See* California Health & Safety Code §§ 42302-42302.3.) This issuance is a limited, ministerial action consisting simply of making a final check to ensure that all applicable conditions were correctly incorporated into the CEC certification. If so, the District issues the Authority to Construct and the air-quality related permit conditions become enforceable by the District under the California Health & Safety Code.

Both the Energy Commission licensing process and the Federal PSD Permit process provide opportunities for public participation. Both processes require the permitting agencies to notify the public of the permit proceeding and invite the public to submit comments on whether a permit should be issued and what permit conditions it should contain. Those who participate in these proceedings and are dissatisfied with the final permit decisions have a right to appeal the decisions. The Energy Commission's licensing decision is appealable directly to the California Supreme Court. The Air District Authority to Construct is appealable to the District's Hearing Board and subsequently to the Superior Court of California. Federal PSD Permits are initially appealable the EPA's Environmental Appeals Board in Washington, D.C., and subsequently to federal court.[2]

B. RUSSELL CITY ENERGY CENTER PERMITTING HISTORY

The proposed Russell City facility was initially licensed in 2002, but it was relocated and so its permits had to be updated. The CEC and the Air District therefore reinitiated the permitting process outlined above to amend the initial permits to reflect the new location. The District prepared a Determination of Compliance addressing air quality issues raised (as well as a few minor changes in the operating conditions) by the permit amendment and submitted it to the Energy Commission for use in the licensing proceeding. The Energy Commission completed its CEQA-equivalent review of environmental impacts (including air quality issues) and ultimately approved the amendment on September 26, 2007. On November 1, 2007, the Air District issued an amended Authority to Construct incorporating the Energy Commission's conditions of certification into a District-issued permit, and also issued the amended Federal PSD Permit for the project. The amended Authority to Construct and the amended Federal PSD Permit were issued jointly in the same document, in accordance with the Air District's administrative practice.

A number of parties then sought review of these permitting actions. On the state-law side, a group of interested organizations attempted to seek reconsideration of the Energy Commission's decision to license the project, but the Energy Commission declined to hear their request. The group then

[2] The Air District's ministerial Authority to Construct permit is appealable only on the narrow issue of whether the Air District correctly incorporated the Energy Commission's conditions of certification in the Authority To Construct. That is, an error in transcribing a permit condition from the Energy Commission's license into the Authority to Construct is appealable, but an appeal cannot seek to revisit substantive issues of what permit conditions are appropriate and required, which are addressed during the CEC licensing process and on any appeals therefrom.

appealed the denial to the California Supreme Court, but the Supreme Court dismissed their petition. One person also appealed the Air District's issuance of the Authority to Construct to the District's Hearing Board, but his appeal was denied and he did not seek further review. All appeal avenues have therefore been exhausted, and the state-law Energy Commission license and District Authority to Construct are not subject to further review.

With respect to the Federal PSD Permit, one person appealed the permit to the Environmental Appeals Board raising issues concerning the public notice and comment process (among other, substantive issues). The Environmental Appeals Board ruled that the Air District had not mailed notice of the proposed amended Federal PSD Permit to several parties that were entitled to it, and so it remanded the permit to the District to re-notice the proposed permit and provide the public with a further opportunity to comment. (*See* Remand Order, *In re Russell City Energy Center*, PSD Appeal No. 08-01 (EAB Jul. 29, 2008) ("Remand Order").[3]) The Air District is re-noticing the proposed amended Federal PSD Permit at this time in response to the Remand Order.

C. THE CURRENT PROPOSED AMENDED PERMIT

The Air District is re-proposing to issue the Federal PSD Permit for the Russell City Energy Center in response to the Order of the Environmental Appeals Board. The Air District is complying with all of the detailed public notice requirements for this proposal, as directed by the Environmental Appeals Board. In accordance with Sections 52.21 and 124.10 of Title 40 of the Code of Federal Regulations, the Air District is proposing to issue the amended permit, publishing notice of its proposal, and inviting public comments on the proposal. Details on how the public can learn more about the project and submit comments about the proposed amended Federal PSD Permit are set forth in Section II.D.

The amendments that have been proposed to the Federal PSD Permit are outlined in detail in the subsequent portions of this document. The Air District is also describing in detail a number of aspects of the project that are not being amended, in order to provide complete information in a single location. The analysis of elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standards for Federal PSD Permits, and that they would comply with current PSD requirements even if they were being proposed anew at this time.

The Air District is not reopening the state-law permitting process that was completed under the Warren-Alquist Act (culminating with the Energy Commission's license for the project and the District's incorporation of the Energy Commission's licensing conditions into the Authority to Construct permit). Those permitting actions under state law are final and all avenues for appeal have been exhausted. The Environmental Appeals Board's remand of the Federal PSD Permit to be re-noticed does not implicate these state-law permits. They are separate legal entities and the Environmental Appeals Board has not questioned their continued validity. The Environmental Appeals Board affirmed the distinction between these two permitting systems in its Remand Order,

[3] The EAB's Remand Order is available on the EAB's website at www.epa.gov/eab. The EAB may also be contacted at 1341 G Street N.W., Washington, D.C., 20005, (202) 233-0122. The public may also be interested in examining the EAB's document "A Citizen's Guide to the Environmental Appeals Board" for more information about the EAB and how it works.

explaining that "[t]he Board will deny review of issues that are not governed by the PSD regulations because it lacks jurisdiction over them." (*See* Remand Order, Slip Op. at p. 40.) It further explained that where a permit requirement is "a California rather than a federal PSD requirement, [it] consequently is not reviewable by the Board." (*See id.*, Slip Op. at p. 41.) As these passages explain, the CEC licensing requirements under the Warren-Alquist Act are state-law requirements outside of the Federal PSD Permit process and are not part of the Environmental Review Board's remand.

D. OPPORTUNITIES FOR PUBLIC PARTICIPATION AND COMMENT ON THE DISTRICT'S PROPOSAL

The District invites all interested parties to comment on the Draft Amended PSD Permit. The legal requirements for PSD Permits are contained in Section 52.21 of Title 40 of the Code of Federal Regulations (40 C.F.R. section 52.21). Comments should address only the Federal PSD issues in this proceeding. The District is not considering any issues related to the state-law Authority to Construct permit or the California Energy Commission's license for the project, or any other non-PSD issues. The EAB provided examples of such non-PSD issues in Section IV.E of its Remand Order. (*See* Remand Order, *In re Russell City Energy Center*, PSD Appeal No. 08-01, Slip Op. at p. 40 (EAB Jul. 29, 2008).) For a complete determination of what are and are not PSD issues, interested parties should consult the EAB's order, 40 C.F.R. section 52.21, other relevant EAB decisions, and related authorities.

Written comments should be directed to Weyman Lee, P.E., Senior Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4796, weyman@baaqmd.gov. The Air District will publish the deadline for submitting written comment in a formal legal notice; interested parties may contact Mr. Lee for further information. The permit application and other materials on which the proposed permit is based will be made available for public review at the District's headquarters at the above address. Interested parties who would like to review such materials should contact the District's public records coordinator by telephone at (415) 749-4761, or electronically at publicrecords@baaqmd.gov. The District will also be holding a public hearing to allow interested parties to comment on the Draft Amended PSD Permit in person. Further information on the date and location of the public hearing will be published with the formal legal notice. The District will consider all comments from all interested parties, whether in writing during the written comment period or orally at the hearing.

III. PROJECT DESCRIPTION

The Russell City Energy Center is a proposed 600 megawatt ("MW") natural gas fired combined-cycle power plant proposed to be built by Russell City Energy Company, LLC, which is owned 65% by a subsidiary of Calpine Corporation and 35% by General Electric Corporation. The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. (A full description of the facility and its air emissions is provided in Sections III and IV below.) The facility was originally permitted in 2002, but was subsequently relocated approximately 1,500 feet north of the original site and required the facility's permits to be amended.

The proposed facility would be 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.

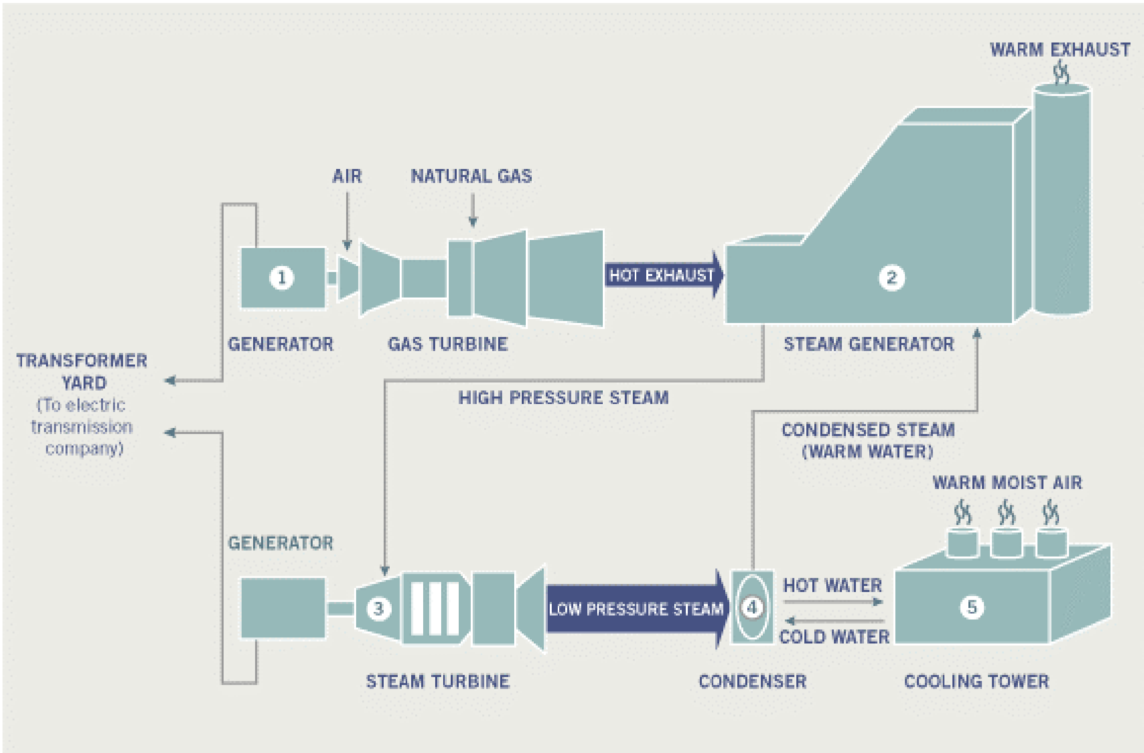
The Russell City Energy Center is proposed to include two gas turbines, a single steam turbine, two heat recovery steam generators (HRSG) or waste heat boilers, a cooling tower, and a diesel fire pump engine. The facility would be considered a combined cycle power plant in which the gas turbines generate electricity and the heat from the gas turbine exhaust is used to produce steam in the heat recovery steam generator to generate additional electricity via the steam turbine. The recovery of energy from the gas turbine exhaust, which otherwise would be wasted, increases the efficiency of electrical generation.

The gas turbines burn natural gas to rotate an electrical generator to generate electricity. The main components of a turbine consist of a compressor, combustor, and turbine. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the power turbine where the gases expand across the turbine blades, driving one or more shafts to power an electric generator.

The waste heat in the exhaust from the gas turbines is sent to the heat recovery steam generator that produces steam that is sent to a steam turbine to generate additional electricity. The heat recovery steam generator has an additional duct burner that provides supplemental heat to create more steam during times of peak energy demand.

The facility would have a cooling tower that acts as a heat exchanger by circulating water to cool various equipment at the site. The cooling tower also recondenses the steam/condensate from the steam turbine and recycles this water back to the heat recovery steam generator. The facility also would have a 300 hp diesel engine to power a fire pump onsite to be used in case of emergency to provide water to fight fires.

The schematic diagram below illustrates how a combined-cycle combustion turbine power plant works.



The Russell City Energy Center 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.

Operating Scenarios:

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

IV. FACILITY AIR EMISSIONS

This section summarizes the proposed facility's air emissions. This summary includes both air emissions subject to Federal PSD requirements and air emissions not covered by the Federal PSD Program. Emissions in the latter category are subject to applicable permitting requirements under other legal requirements, and are summarized here to provide a complete picture of the facility's proposed emissions. The emissions specifically subject to Federal PSD permitting requirements are identified at the end of this section, in Subsection IV.D.

A. CRITERIA AIR POLLUTANTS

In this section, the Air District provides an overview of the proposed project's emissions of air pollutants known as "criteria" air pollutants. In general, criteria pollutants are regional air pollution problems for which California and the federal government have established ambient air quality standards.

1. Maximum Hourly Emissions

The facility's maximum hourly emissions from the combustion turbines and heat recovery boilers under various operating scenarios are set forth in the tables below.

Table 1 is a summary of maximum hourly emissions from the facility during normal (baseload) operations.

Table 1: Steady-State Emissions Rates

Pollutant	Emissions Rate (lb/hr)[a]
NOx (as NO_2)	16.45
CO	19.96
POC (as CH_4)	2.86
PM_{10}	9.0
SOx (as SO_2)	6.2

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

Table 2 is a summary of maximum hourly emissions for startup and combustor tuning operations, as well as maximum total emissions per startup/tuning event.

Table 2: Startup and Tuning Emissions Rates

Pollutant	Cold Startup/Tuning[a]		Warm Startup[b]		Hot Startup[c]	
	lb/hr	lb/startup[g]	lb/hr	lb/startup	lb/hr	lb/startup
NOx (as NO_2)[d]	97.2	480.0	83.8	125	83.8	125
CO[d]	1348.8	5028	1154.2	2514	1154.2	2514
POC (as CH_4)[d]	14.9	83	26.3	79	14.8	35.3
PM_{10}[e]	9.0	54	9.0	27	9.0	27
SOx (as SO_2)[f]	6.2	33	6.2	16.5	6.2	16.5

[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] warm starts not to exceed 3 hours (180 minutes); by definition occurs between 8 and 72 hours of a shutdown.
[c] hot starts not to exceed 3 hours (180 minutes); by definition, occurs within 8 hours of a shutdown.
[d] maximum hourly emissions for NO_x, CO, and UHC provided by applicant.
[e] 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
[f] 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
[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 3 is a summary of maximum emissions per shutdown event.

Table 3: Maximum Emissions per Shutdown Event

Pollutant	lb/shutdown[a]
NOx (as NO_2)	40[b]
CO	902
POC (as CH_4)	16
PM_{10}	4.5
SOx (as SO_2)	3.1

[a] Shutdowns not to exceed 30 minutes.
[b] 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.

2. Maximum Daily Air Emissions

Table 4 is a summary of the daily maximum criteria air pollutant emissions for the permitted sources at the proposed Russell City Energy Center.

Table 4: Maximum Daily Criteria 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	216	148.8
S-3 Gas Turbine & S-4 HRSG[a]	776	5387	148	216	148.8
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

3. Maximum Annual Air Emissions

Table 5 below summarizes the maximum operating annual air pollutant emissions for the proposed project. This table reflects two minor changes from the project as initially permitted: The Carbon Monoxide emissions have decreased from 584.2 tons/year to 389.3 tons/year, and the Particulate Matter emissions have increased slightly from 86.4 tons/year to 86.8 tons/year. All other emission rates are unchanged from the project as initially permitted.

Table 5: Maximum Annual Emissions of Criteria Air Pollutants

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**

B. TOXIC AIR CONTAMINANT (TAC) EMISSIONS

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

Table 6 also provides the TAC emission rates that the Air District used as the basis for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. This health risk assessment is required by District Regulation 2, Rule 5. The health risk assessment is conducted to determine the potential impact on public health resulting from the worst-case TAC emissions from the project. If emissions are above certain established screening levels prescribed in Table 2-5-1 of Regulation 2, Rule 2, a health risk assessment is required. The applicable screening levels from Table 2-5-1 are also included in Table 6. Where no acute trigger level is listed for a TAC, none has been established for that TAC.

Table 6: 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	2330	64		
Acrolein	321	2.3	0.0403	0.00042
Ammonia	121000	7700	15.2	7.1
Benzene	226	6.4	0.0284	2.9
1,3-Butadiene	2.16	1.1		
Ethylbenzene	304	77000		
Formaldehyde	15600	30	1.96	0.21

Table 6: 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)**
Hexane	4400	270000		
Naphthalene	28.2	0.011		
Total PAHs	1.8	0.011		
Propylene	13100	0.012		
Propylene Oxide	813	49	0.102	6.8
Toluene	1210	12	0.151	82
Xylenes	408	27000		
Cooling Tower				
Ammonia	186	7700	0.0212	7.1
Arsenic	0.155	0.012	0.0000177	0.00042
Cadmium	0.248	0.045		
Hexavalent chromium	1.27	0.0013		
Copper	1.88	93		
Lead	0.588	5.4	0.0000671	0.22
Manganese	2.58	7.7		
Mercury	0.00186	0.56		
Nickel	1.45	0.73	0.000166	0.013
Selenium	0.216	770		
Zinc	5.94	1400		
Firepump Engine				
Diesel Exhaust Particulate	4	0.58		

Notes: 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 Air District Regulation 2, Rule 5.

Table 7 is a summary of the health risk assessment results.

Table 7: 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

Pursuant to BAAQMD Regulation 2-5, the increased carcinogenic risk attributed to this project is 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 not significant since each is less than 1.0. These levels of risk are less than significant.

C. SECONDARY EMISSIONS AND EMISSIONS FROM GROWTH ASSOCIATED WITH THE PROJECT

The Federal PSD Regulations require that the District's analysis of the emissions from the proposed project include "secondary emissions" associated with the project and emissions from "general commercial, residential, industrial and other growth associated with the project." (*See* 40 C.F.R. §§ 52.21(k) & 52.21(o)).

<u>Secondary Emissions</u>

"Secondary Emissions" are emissions that are associated with a source but are not emitted from the source itself. They are emissions from any facility that is not part of the source subject to the Federal PSD Permit, but which would not be constructed unless the facility under review is conducted. The proposed Russell City Energy Center will not have any such secondary emissions.

<u>Associated Growth</u>

"Associated Growth" is additional commercial, residential, industrial and other growth that the project may cause or induce. This type of growth is growth in the local workforce and support infrastructure necessary to serve the proposed facility. Examples include additional residential housing, retail suppliers, and additional schools and municipal services that would be necessary to accommodate any new workers that would come to the area to work in the facility. Examples also include any additional commerce or industry necessary to provide goods and services used by the facility, maintenance facilities to serve the facility, and other similar support operations. Emissions from "associate growth" are the emissions associated with this additional human and economic activity generated as a result of the facility under review. The Air District undertook an associated growth analysis and found that there would be no significant associated growth.[4]

D. AIR EMISSIONS SUBJECT TO FEDERAL PSD PERMIT REQUIREMENTS

[4] *See* Air Quality Impacts Analysis, Exhibit C.

1. Emissions Regulated Under the Federal PSD Program

The Federal PSD Program does not apply to all air pollutants. The program does not apply to air pollutants for which the ambient air quality in the Bay Area exceeds the health-based National Ambient Air Quality Standards ("NAAQS"). For air pollutants for which the Bay Area exceeds those standards – for which we are designated as "non-attainment" – the District's "New Source Review" regulations apply, which have additional requirements beyond the Federal PSD Program such as providing Emission Reduction Credits to offset emissions from new projects. The Federal PSD Program applies only to those pollutants for which the District is designated as being in "attainment" of the NAAQS, or for which EPA has made no formal designation of "attainment" or "non-attainment". The Bay Area is currently designated as "non-attainment" for ozone, meaning that ozone and its precursors (NOx and VOC) are not subject to PSD review.[5]

Furthermore, the Federal PSD Permit Regulations apply only to facilities that are considered "major sources" of PSD-regulated air pollutants Regulations. A proposed power plant is considered a "major source" if it would emit more than 100 tons per year of any Regulated Air Pollutants. (*See* 40 C.F.R. § 52.21(b)(1)(i)(a).) The main substantive requirements of the Federal PSD Permit program – the use of Best Available Control Technology to minimize emissions of Federal PSD Pollutants and an Air Quality Impact Analysis of the effect of the source on ambient air quality – apply where the source will emit Regulated Air Pollutants in "significant" amounts as set forth in Section 52.21(b)(23).

In addition, EPA has provided special regulatory direction for Federal PSD Permits for one specific regulated air pollutant that is implicated in this Federal PSD Permit analysis, Particulate Matter. EPA has long regulated one subset of Particulate Matter, particulate matter of less than 10 microns in diameter (PM_{10}). Recently, a related subset of Particulate Matter has recently come under heightened regulatory scrutiny, Particulate Matter of less than 2.5 microns in diameter ($PM_{2.5}$). EPA promulgated National Ambient Air Quality Standards ("NAAQS") for $PM_{2.5}$ in 1997 (with an update in 2006), and designated certain regions of the country as non-attainment with those Standards in 2005. The Bay Area was not designated as non-attainment, and is currently unclassified for purposes of attainment of the 24-hour NAAQS for $PM_{2.5}$, which means that $PM_{2.5}$ falls under the federal PSD program as set forth in 40 C.F.R. section 52.21.

EPA has recognized, however, that there are a number of difficulties involved in regulating $PM_{2.5}$ as a distinct pollutant from PM_{10}, including a lack of adequate tools to calculate emissions of $PM_{2.5}$ and related precursors, a lack of adequate modeling techniques to project ambient impacts, and a lack of $PM_{2.5}$ monitoring sites. EPA has therefore directed that implementing agencies should use PM_{10} as a surrogate for analyzing $PM_{2.5}$ emissions and impacts for PSD purposes in guidance issued October 23, 1997.[6] EPA recently promulgated new amendments to the PSD regulations addressing $PM_{2.5}$, and these amendments expressly incorporated the earlier guidance and made clear that for permit

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[5] For information on the Bay Area's attainment status for various air pollutants, including attainment of both state and federal ambient air quality standards, see http://www.baaqmd.gov/pln/air_quality/ambient_air_quality.htm.

[6] Memorandum from John Seitz, Director of EPA Office of Air Quality Protection and Standards, to EPA Regional Staff, entitled "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" (Oct. 23, 1997).

applications such as this one that were submitted and complete before July 15, 2008, permitting agencies should use the PM_{10} surrogate approach from the 1997 guidance.[7]

Furthermore, it is worth noting that use of PM_{10} as a surrogate for $PM_{2.5}$ is especially appropriate in this instance because for combustion sources such as those that will be used at the Russell City Energy Center fired on clean-burning natural gas, the majority of particulate matter emissions will have a diameter of less than 1 micron. (*See* EPA AP-42 Emission Factors, Section 1.4, 7/98.) As this particulate matter is less than 1 micron in diameter, by definition it has a diameter of less than 2.5 microns and less than 10 microns, and so it is *both* $PM_{2.5}$ and PM_{10}. The analysis of potential PM_{10} impacts is therefore a useful and appropriate surrogate for potential $PM_{2.5}$ impacts from power plant projects such as the Russell City Energy Center.

For all of these reasons, the District is following a PM_{10} surrogate approach. The District is analyzing PM_{10} emissions and related impacts as a surrogate for $PM_{2.5}$ emissions and impacts, and is implementing applicable PM_{10} PSD regulatory requirements as a surrogate for PSD for $PM_{2.5}$. Throughout this document, the District uses the generic reference "Particulate Matter" to include both PM_{10} and $PM_{2.5}$.

2. Russell City Emissions Subject to PSD Permitting Requirements

Under this regulatory framework, the Federal PSD Permit analysis applies only to regulated air pollutants for which the Bay Area is not designated as "non-attainment" of an established NAAQS and which will be emitted in "significant" amounts from a "major facility".[8] **Table 8** compares the emissions from the proposed Russell City Energy Center (excluding the "non-attainment" pollutants referenced above) with the applicable PSD "Major Facility" and "Significance" thresholds published in 40 C.F.R. Sections 52.21(b)(1) and (b)(23).[9]

Table 8:
Maximum Annual Facility Regulated Air Pollutant Emissions

[7] *See* 73 Fed. Reg. 28231, 28349-50 (May 16, 2008) (to be codified at 40 C.F.R. § 52.21(i)(1)(xi)). The Air District expects shortly to be classified as "attainment" or "non-attainment" of the new $PM_{2.5}$ standard by EPA. If the District is classified as "non-attainment", $PM_{2.5}$ will be regulated under the District's NSR permitting program and will no longer be subject to PSD permit requirements. Permit applications such as this one that were received under the existing designation will continue to be processed under the PSD program using the surrogate approach as directed by EPA, however.

[8] Note that the other air emissions not subject to the Federal PSD Permit analysis are not unregulated. They are subject to other stringent regulatory requirements under state law.

[9] Emissions rates in Table 8 are based on the emissions rates set forth in Section IV.A. above with one exception, sulfuric acid mist (H_2SO_4). Emissions of sulfuric acid mist are expected to be less than the PSD significance threshold of 7 tons per year, and the Air District is proposing 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 annual compliance source tests. The annual 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. With this permit condition, sulfuric acid mist emissions will be less than the PSD significance threshold of 7 tons per year and the facility will not be subject to Federal PSD Permit requirements for sulfuric acid mist.

Pollutant	Emissions (tons/year)	PSD "Major Facility" Trigger (tons/year)	PSD "Significance" Threshold (tons/yr)
Nitrogen Dioxide (NO_2)	134.6	100	40
Carbon Monoxide (CO)	389.3	100	100
Particulate Matter (PM_{10})	86.8	100	15
Sulfur Dioxide (SO_2)	12.2	100	40
Sulfuric acid mist (H_2SO_4)	<7	100	7

As Table 8 shows, the proposed facility will be considered a "major facility" subject to PSD permitting requirements because it exceeds the 100 tons-per-year threshold. Emissions will be "significant" for NO_2, Carbon Monoxide and Particulate Matter.

V. FEDERAL "BEST AVAILABLE CONTROL TECHNOLOGY" ANALYSIS

The Federal PSD Regulations (40 C.F.R. Section 52.21) require that a new major stationary source such as the Russell City Energy Center apply the "Best Available Control Technology" for each regulated pollutant that it will have the potential to emit in significant amounts. As noted above, the Russell City Energy Center will have the potential to emit three pollutants subject the Federal PSD regulation in significant amounts: NO_2, Carbon Monoxide, and Particulate Matter. The facility must therefore demonstrate that it will use the "Best Available Control Technology" to limit emissions of those three pollutants.

The Federal PSD Regulation defines "Best Available Control Technology" as:

> An emissions limitation . . . based on the maximum degree of reduction for each pollutant subject to regulation under Act [sic] which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

EPA has provided further guidance on how to implement this definition of "Best Available Control Technology" in its 1990 Draft New Source Review Workshop Manual ("NSR Workshop Manual"). EPA requires that the District implement the Best Available Control Technology requirement by conducting what EPA calls a "Top-Down BACT Analysis". As described in EPA's NSR Workshop Manual, a "Top-Down BACT Analysis" consists of five key steps:

1. **Identify control technologies** including Lowest Achievable Emission Rate (LAER) technologies.
2. **Eliminate technically infeasible options.**
3. **Rank remaining control technologies by control effectiveness.** This ranking should include control efficiencies, expected emission rate, expected emissions reduction, energy impacts, environmental impacts, and economic impacts. If the top control alternative is chosen, then cost and other detailed information about other control options need not be provided.
4. **Evaluate the most effective controls and document results.** Analysis to include a case-by-case consideration of energy, environmental, and economic impacts. If the top control alternative is selected, other potential impacts are considered to determine if the selection of an alternative control option can be justified. If the top control option is not selected as BACT, evaluate the next most effective control option.

   The cost estimation methodology used in this BACT analysis is consistent with the latest EPA guidance (EPA's Office of Air Quality Planning and Standards [OAQPS] Control Cost Manual [EPA 453/b-96-001]), and the District's BACT handbook.

5. **Select the "Best Available Control Technology"**, which will be the most effective option not rejected in Step 4.

Once the selection of "Best Available Control Technology" is made under the "Top-Down BACT Analysis", the Air District is then required to derive a numerical emissions limit that can be achieved by the selected control technology (or some other type of enforceable limit if a numerical limit is not feasible), and then implement that emissions limit in a legally-enforceable condition in the Federal PSD Permit.

The Air District's "Best Available Control Technology" analysis for the three Federal PSD Permit pollutants (NO_2, Carbon Monoxide and Particulate Matter) is set forth in this section. The District has examined the Best Available Control Technology for each of the types of equipment at the facility that will have air emissions: the gas turbine/heat recovery boiler power generation equipment; the cooling tower; and the emergency diesel fire pump.

A. Gas Turbine/Heat Recovery Boiler Power Generation Equipment

The following section provides the District's BACT analysis for the project's gas turbines and heat recovery boiler duct burners for each of the three Federal PSD Permit pollutants. Each gas turbine/heat recovery boiler combination will have a common exhaust stream and exhaust through a common stack, and so the BACT analyses are undertaken for the Gas Turbine/Heat Recovery Boiler power train as a combined unit.

1. Best Available Control Technology for Nitrogen Dioxide (NO_2)

NO_2 emissions are a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_2 is formed when the heat of combustion causes the nitrogen molecules in the combustion air to dissociate into individual nitrogen atoms, which then combine with oxygen atoms form nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as nitrogen oxides (NO_x).[10] This reaction primarily forms NO (95% to 98%) and only a small amount of NO_2 (2% to 5%), but the NO eventually oxidizes and converts to NO_2 in the atmosphere.

NO_2 is a reddish-brown gas with detectable odor at very low concentrations, and is regulated as an air pollutant in its own right. NO_2 is also regulated (along with NO) as a precursor to the formation of ground-level ozone, the principal ingredient in smog.[11] In the context of ozone precursor regulation, NO_2 and NO emissions are generally referred to collectively as "NO_x". As the NO portion of NO_x eventually converts to NO_2, and as permit limits for NOx are normally expressed in terms of NO_2, the Air District refers to NO_x and NO_2 interchangeably in this analysis. The

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

[11] NOx emissions as an ozone precursor are regulated under California law through the Energy Commission Licensing process and subsequent Air District Authority to Construct permit (discussed in more detail in Section II.A above). NO_2 is regulated under the Federal PSD program for sources in the Bay Area.

technologies that are effective to target NO_2 as a pollutant in its own right are the same technologies that are effective to target NO_x as an ozone precursor.

STEP ONE: Identify Control Technologies

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

Combustion Controls

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

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

It should be noted, however, that techniques that control NOx by reducing combustion temperature could involve a trade-off with the formation of other pollutants. Reducing combustion temperature to limit NOx formation can decrease combustion efficiency, resulting in increased byproducts of incomplete combustion such as Carbon Monoxide and unburned hydrocarbons. (Unburned hydrocarbons from natural gas combustion consist of methane, ethane and Precursor Organic Compounds.) The Air District prioritizes NOx reductions over Carbon Monoxide and POC emissions, however, because the Bay Area is not in compliance with applicable ozone standards but does comply with Carbon Monoxide standards. The Air District therefore requires applicants to minimize NOx emissions to the greatest extent feasible, and then optimize CO and POC emissions for that level of NOx control. This is a trade-off that must be kept in mind when selecting appropriate emissions control technologies for these pollutants.

The Air District has identified the following available combustion control technologies for reducing NOx emissions from the combustion turbines and heat recovery boiler duct burners.

Steam/Water Injection: Steam or water injection was one of the first NOx control techniques utilized on gas turbines. Water or steam is injected into the combustion zone to act as a heat sink, lowering the peak flame temperature and thus lowering the quantity of thermal NO_x formed. The injected water or steam exits the turbine as part of the exhaust. The lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion, however, and so Carbon Monoxide and POC emissions can increase as water/steam-to-fuel ratios increase. In addition, the injected steam or water may cause flame instability and can cause the flame to quench (go out). This is especially a concern with the duct burners in the heat recovery boiler because they use turbine exhaust for their combustion air, which has a low oxygen content and is less able to support a stable flame. Also, the duct burners are comprised of many small modular burners located in the cross sectional area of the duct, and it is not feasible to inject steam/water since the flame is not concentrated. For these reasons, steam/water injection technology cannot be used for the duct burners.

Low-NOx Combustion Technology: Another technology that can control NOx without water/steam injection is low-NOx burner technology. For the combustion turbines, **Dry Low-NO_x Combustors** reduce the formation of thermal NO_x through (1) "lean combustion" that uses excess air to reduce the primary combustion temperature; (2) reduced combustor residence time to limit exposure in a high temperature environment; (3) "lean premixed combustion" that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen and then a secondary lean burn-stage to complete combustion in a cooler environment. For the heat recovery boiler duct burners, **Low NO_x Duct Burners** are designed to minimize NO_x emissions. Duct burners in a heat recovery boiler are inherently lower in NO_x formation since the combustion air – turbine exhaust gas – has a lower oxygen content that results in lower flame temperatures.

Catalytic Combustors: Catalytic combustors, marketed under trade names such as XONON™, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NO_x formation. XONON™ uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. This technology is available only for the combustion turbines; there are no catalytic combustor technologies for the heat recovery boiler duct burners.

Post-Combustion Controls

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

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

Selective non-catalytic reduction (SNCR): Selective non-catalytic reduction involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1400° to 2000° F and is most commonly used in boilers because combustion turbines do not have exhaust temperatures in that range.

EMx™: EMx™ (formerly SCONOx™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NO_x, CO, VOC and optionally SO_x emissions for gas turbine applications. A coated catalyst oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, and the NO_2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regenerative gas is periodically passed through the catalyst to desorb the NO_2 from the catalyst and reduce it to elemental nitrogen (N_2). No ammonia is used by the EMx process. The EMx catalyst requires replacement periodically.

STEP TWO: Eliminate Technically Infeasible Options

After identifying the potential control technologies that may be available to reduce NO_2 emissions, the Air District then evaluated whether each of them is technically feasible for this project.

Combustion Controls

Both steam/water injection and dry low-NOx combustors are available technologies and have been utilized in many combustion turbine applications. Steam/water injection is not appropriate for use with the heat recovery turbine duct burners, as noted above. Low-NOx burners are the only combustion control technology available for the duct burners.

Catalytic combustors such as XONON™ have not been demonstrated on large-scale utility gas turbines such as the Siemens 501F. The technology has been successfully demonstrated in a 1.5 megawatt simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 megawatts, but it is not currently available for turbines of the size proposed for the Russell City Energy Center.[12]

Post-Combustion Controls

Selective Catalytic Reduction (SCR) with ammonia injection is a proven post-combustion NOx control technique widely used on numerous utility-scale gas turbines/HRSGs. These systems are commercially available from several vendors.

Selective non-catalytic reduction (SNCR) requires a temperature window that is higher than the exhaust temperatures from utility combustion turbine installations. Therefore, SNCR is not technically feasible for this project.

EMx™ has been successfully demonstrated on several small combustion turbine projects up to 45 megawatts, and the manufacturer has claimed that it can be effectively scaled up and made available for utility-scale turbines.[13] Based on this information, it would not be appropriate to eliminate EMx™ as a technically feasible control technology at this stage.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

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[12] Kawasaki Heavy Industries purchased the XONON™ catalytic combustion technology from Catalytica Energy Systems in 2006. Kawasaki plans to use the XONON™ on its own turbines, but it is not known if Kawasaki will make the combustors available to other turbine manufacturers.

[13] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006.

Next, the Air District evaluated each of the feasible control technologies and ranked them in order of effectiveness at reducing NO_2 emissions.

For the combustion controls, Dry Low-NOx burners used with Low-NOx duct burners can feasibly achieve NOx emissions as low as 9 ppm.[14] Water/steam injection in the combustion turbines used in conjunction with Low-NOx duct burners can achieve NOx emissions as low as 25 ppm.[15] The Air District therefore ranks Dry Low-NOx Combustors/Low-NOx Duct Burners as the No. 1 control technology; and water/steam injection with Low-NOx Duct Burners as the No. 2 control technology.

For the post-combustion controls, both SCR and EMx™ are equally effective and can achieve a NOx emissions concentration of 2 ppm @15% O2 averaged over one hour.[16] Both technologies therefore share the top ranking.

STEP FOUR: Evaluate the most effective controls and document results

Combustion Controls

The Air District has found no adverse economic, energy, or collateral environmental impacts that counsel against using the most effective control technology, Low-NOx burner technology. The Air District is therefore proposing the use of Dry Low-NOx combustors for gas turbines and Low-NOx burners for the heat recovery boilers as BACT. Selection of the most effective control technology in the hierarchy ends the Top-Down BACT analysis for combustion controls.

Post-Combustion Controls

For the post-combustion controls, the top two technologies, Selective Catalytic Reduction (SCR) and EMx™, are equally effective and share the No. 1 ranking. The Air District has found that both technologies would involve certain economic, environmental, and energy impacts, and has therefore evaluated both technologies to determine whether these impacts suggest that either technology should be eliminated as BACT. The Air District has concluded that neither alternative should be eliminated as an appropriate BACT alternative.

Economic Impacts

The Air District evaluated the cost of each control technology compared with the emissions reductions it can achieve. The Air District determined that both technologies can achieve NO_2 emission reductions of 739.1 tons per year,[17] but that EMx will cost approximately $5,200,000 per

[14] R. Peltier, *Gas turbine combustors drive emissions toward nil*, Power, March 2003.
[15] B. Bueker, *Basics of Boiler and HRSG Design*, PennWell, 2002, pp 133-135.
[16] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006.
[17] The emissions reductions are based upon uncontrolled NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr.

year, more than the $2,350,000 approximate annual cost of SCR.[18] This analysis is based on a single GE Frame 7FA gas turbine of an equivalent capacity to the Siemens F5000, equipped with a Dry-Low NOx combustor achieving an NO_x emission rate of 25 ppmvd @ 15% O_2.[19]

Collateral Environmental Impacts

<u>SCR:</u>

The use of SCR will result in ammonia emissions because some of the ammonia used in the reaction to convert NOx to nitrogen and water does not get reacted and remains in the exhaust stream. These ammonia emissions are known as "ammonia slip". Ammonia is a toxic chemical that can irritate or burn the skin, eyes, nose, and throat. The Air District has conducted a health risk assessment using air dispersion modeling to evaluate the potential health impacts of all toxics emissions from the facility, including ammonia slip. This assessment showed an acute hazard index of 0.024 and a chronic hazard index of 0.007. (*See* Health Risk Assessment, Appendix B.) A hazard index under 1.0 is considered less than 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.

A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored on-site in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases. Moreover, the CEC has modeled the health impacts arising from a catastrophic ammonia release and has found that the impacts would not be significant.[20] The potential environmental impact from aqueous ammonia transportation and storage does not justify the elimination of SCR as a control alternative.

The Air District also evaluated the potential for ammonia slip emissions 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. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being "nitric acid

[18] EPA's NSR Workshop Manual provides that both average cost-effectiveness and incremental cost effectiveness should be considered in the BACT analysis. Since both technologies can achieve the same level of emission reductions, there is no incremental cost effectiveness to evaluate, as neither technology is incrementally better than the other.

[19] The annualized SCR cost figures are based on a cost analysis conducted by ONSITE SYCOM Energy Corporation, updated and adjusted for inflation by the District. These total 1999 annualized cost for SCR was adjusted for inflation by the District using the Consumer Price Index (2008 value = 1999 value x 1.32). Emerachem provided the updated cost information for the EMx.

[20] California Energy Commission (CEC), 2002a. Final Staff Assessment (FSA) and Addendum, published on June 2002. California Energy Commission (CEC) Final Staff Assessment (FSA) Part 1 and Part 2, Section 4.4, Hazardous Materials Management, published on June 2007.

limited".[21] Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative.

EMx

The use of EMx will require approximately 360,000 gallons of water per year for catalyst cleaning. EMx will also require the use of natural gas for catalyst regeneration. SCR will not have these impacts as the SCR catalyst does not normally require periodic cleaning and regeneration. These environmental impacts do not justify the elimination of EMx as a control alternative.

Energy Impacts

SCR and EMx will both reduce the energy efficiency of the gas turbine/heat recovery boiler power generation trains. These post-combustion controls reduce the energy output per unit of fuel because ancillary equipment such as pumps and control systems require power produced by the plant that would otherwise have gone to the electric grid. In addition, the catalyst beds in both systems are obstructions that create a pressure drop in the exhaust flow across the bed, which requires the combustion turbines to fire additional fuel to increase the exhaust pressure to overcome this back-pressure. Both of these systems will therefore increase fuel consumption per unit of power output. This energy loss will be approximately 67,900 million BTU per year if SCR is used. For EMx, the energy loss will be nearly twice that, approximately 122,000 million BTU per year for the EMx.[22]

Conclusions

Both SCR and EMx would be appropriate BACT post-combustion control alternatives for reducing NO_2 emissions. Both would have the potential for adverse economic, environmental or energy impacts, but none of these impacts would be significant enough to eliminate either of the technologies as BACT. The comparison between these impacts is summarized in Table 9 below.

Table 9: Summary of Collateral Impact Comparison – SCR vs. EMx

Control Alternative	Emission Reductions	Annualized Cost	Cost Effective-ness	Significant Toxics Impacts?	Other Significant Envt'l Impacts?	Energy Impacts
EMx	739.1 tons/yr	$5,265,241	$7,124/ton	No	No	122,000 MMBtu/yr
SCR	739.1 tons/yr	$2,348,898	$3,178/ton	No	No	67,900 MMBtu/yr

STEP FIVE: Select the BACT technology

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[21] BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.
[22] *See* "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000.

As both SCR and EMx™ are equally effective in reducing NOx emissions and are ranked No. 1 in the post-combustion control hierarchy, and neither has significant energy, economic, or environmental impacts that would eliminate it as a BACT alternative, the Air District would consider either as BACT for this project. The applicant has proposed SCR as the post-combustion control, and the Air District therefore adopts this technology as the BACT alternative. As noted above, the Air District has selected low-NOx burner technology for the BACT combustion controls. Together, these technologies represent the Best Available Control Technologies for reducing NO_2 from the combustion turbines/heat recovery boilers.

Determination of BACT emissions limit for NO_2

The Air District also reviewed the NOx emissions limits of other large combined-cycle power plants using SCR systems. These facilities are subject to NOx limits as set forth in the tables below.

Table 10:
NOx Emission Limits for Large Combined-Cycle Power Plants using SCR

Facility	NOx (ppmvd@15%O2)
Hanging Rock, OH-0252	3 (3-hr)
Three Mountain, Shasta County	2.5 (1-hr)
Calpine Facility, Feather River AQMD	2.5 (1-hr)
La Paloma, SJVAPCD	2.5 (1-hr)
Elk Hills, SJVAPCD	2.5 (1-hr)
BP Cherry Point, WA-0328	2.5 (3-hr)
Metcalf Energy Center	2.5 (1-hr)
SMUD Clay Station, SMAQMD	2 (1-hr)
IDC Bellingham, MA	2.0/1.5 (1-hr)
Magnolia Power Project	2 (3-hr)
Magnolia, SCAQMD	2 (3-hr)
Palomar Energy Project	2 (1-hr)
Sacramento Municipal Utilities District, Consumnes	2 (1-hr)
Sunset Power, SJVAPCD	2 (1-hr)
Morro Bay – Duke	2 (1-hr)
Wellton Mohawk, AZ-0047	2 (3-hr)
FPL Turkey Point, FL-0263	2 (24-hr)
Wanapa Energy Center, OR-0041	2 (3-hr)
CPV Warren, VA-0308	2 (1-hr)
Colusa Generating Station	2 (1-hr)

As the table shows, emissions of 2.0 ppm NOx averaged over 1 hour is the most stringent performance standard that has been determined to be achievable at any similar facility using SCR for

NOx control.[23] Based on NOx emissions limits at similar facilities as shown in Table 10 above, the Air District is proposing 2.0 ppm, averaged over 1 hour, as the BACT emission limit for NOx. The Air District is also proposing corresponding hourly, daily and annual mass emissions limits based on the size of the facility. Compliance will be measured on a continuous basis using a Continuous Emissions Monitor.

2. Best Available Control Technology for Carbon Monoxide (CO)

This Section covers the Top-Down BACT analysis for carbon monoxide emissions from the gas turbine/heat recovery steam generator (HRSG) power generation trains.

STEP ONE: Identify Control Technologies

As with NO_2, the Air District has examined both combustion controls to reduce the amount of Carbon Monoxide generated and post-combustion controls to remove Carbon Monoxide from the exhaust stream.

Combustion Controls

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

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

Good Combustion Practices: The Air District has identified good combustion practices as an available combustion control technology for minimizing Carbon Monoxide formation during combustion. Good combustion practices utilize “lean combustion” – large amount of excess air – to produce a cooler flame temperature to minimize NO_x formation, while still ensuring good air/fuel mixing with excess air to

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[23] One facility, the IDC Bellingham facility in Massachusetts, was permitted with a two-tiered NOx emissions limit that required the facility to maintain emissions below 1.5 ppm during normal operations but allowed emissions of up to 2.0 ppm as an absolute not-to-exceed limit. (Note that the facility was never built.) This two-tiered limit recognized that emissions can be highly variable depending on operating circumstances, and will have relatively lower emissions at some times and relatively higher emissions at other times. The proposed Russell City project is expected to exhibit the same type of variation in emissions under the various operating scenarios it will face, and will have emissions as high as 2.0 under some circumstances. The Air District is therefore proposing a 2.0 ppm limit to ensure that the limit will be achievable under all operating conditions.

achieve complete combustion, thus minimizing CO emissions. These good combustion practices can be used with the low-NOx combustion technologies selected for minimizing NOx emissions (Dry Low-NO_x Combustors and Low-NO_x duct burners for the heat recovery boilers).

Post-Combustion Controls

The Air District has also identified two post-combustion technologies to remove Carbon Monoxide from the exhaust stream.

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

EMx™: EMx, described above in the NO_2 discussion, is a multimedia control technology that abates CO and POC emissions as well as NO_x. EMx™ technology uses a catalyst to oxidize Carbon Monoxide emissions to form CO_2, and is therefore also an oxidation catalyst. However, it is not a stand-alone oxidation catalyst since the EMx is also a NOx reduction device. Hence, it is identified as a device separate from the oxidation catalyst.

STEP TWO: Eliminate Technically Infeasible Options

Good combustion practice is a feasible control technique for the gas turbines and duct burners in the heat recovery boiler.

Both EMx™ and Oxidation Catalyst technology are technically feasible options for eliminating Carbon Monoxide from the post-combustion exhaust stream. EMx™ has been demonstrated on a 45 MW Alstom GTX 100 gas turbine at the Redding Electric Municipal Plant in Redding, CA. Oxidation catalysts are installed at numerous similar facilities throughout the state.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Combustion Controls

Good combustion practice is the only combustion technology identified for reducing the formation of Carbon Monoxide during combustion, and so it is ranked No. 1.

Post-Combustion Controls

The Air District considers EMx and the use of an Oxidation Catalyst to be equivalent technologies for CO post combustion control. Both EMx™ and Oxidation Catalyst are capable of maintaining Carbon Monoxide in the range of 2-4 ppmvd @15% O_2 (3-hour average), depending on load and combustor tuning (as emissions from the combustion turbines/heat recovery boilers vary greatly depending on these factors).[24] The Air District ranks both of these post-combustion control technologies equally as No. 1 for control effectiveness.

STEP FOUR: Evaluate Most Effective Controls and Document Results

Good Combustion Practice

The Air District selects the top combustion control technology, good combustion practice, as the BACT combustion control technology. The Air District has not identified any collateral environmental or other impacts that would suggest that this choice is not appropriate as BACT. Thus, no further top-down analysis is required.

Post-Combustion Controls

EMx and Oxidation Catalyst technologies are expected to have similar energy and environmental impacts. The use of either an Oxidation Catalyst or EMx will require replacing the catalyst bed after a number of years in service. The waste catalyst would need to be disposed of in accordance with applicable local, state and federal regulations regarding waste and hazardous waste disposal. These impacts do not justify eliminating either control technology as a BACT alternative. The Air District would therefore be willing to accept either alternative as BACT. As both alternatives are ranked equally as the No. 1 most effective alternative and have no collateral impacts that would rule them out as an appropriate BACT selection, the choice of either would not require further top-down BACT analysis.

STEP FIVE: Select BACT

As noted above, the choice of post-combustion control technology for Carbon Monoxide is influenced by the choice for NOx. The Air District prioritizes NOx control over Carbon Monoxide control because the Bay Area is not in compliance with the federal standards for ozone, which is formed by NOx emissions reacting with other pollutants in the atmosphere, but is in compliance with applicable standards for Carbon Monoxide. The Air District therefore addresses NOx controls first, and then optimizes Carbon Monoxide controls for the control strategy adopted for NOx.

For this project, the Air District has determined that the choice of SCR and not EMx is appropriate for the BACT control strategy for NOx, as described above. The Air District will therefore not require EMx as the control technology for Carbon Monoxide either. This determination is consistent with the BACT goal of requiring the most effective control technology available, as the Oxidation Catalyst alternative was ranked No. 1 as the most effective option, equally with EMx.

Based on the foregoing analysis, the Air District selects the combination of good combustion practices to reduce Carbon Monoxide during combustion and an Oxidation Catalyst to remove Carbon Monoxide from the exhaust stream as BACT.

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[24] S. DeCicco, T. Girdlestone, J.A. Cole, *High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines*, April 27, 2006. Oxidation catalysts have met these BACT permit limits at numerous similar facilities throughout the state. In addition, the District has reviewed Continuous Emissions Monitoring (CEM) data and source test data from a similar facility using an Oxidation Catalyst to abate CO emissions.

Determination of BACT Emissions Limit for Carbon Monoxide (CO):

To establish a BACT permit limit for Carbon Monoxide, the Air District reviewed Continuous Emission Monitor Summary data from a similar facility for the period from August 2005 until August 2008.[25] Like the proposed Russell City project, this facility uses Siemens F-Class turbines and is abated by SCR units and Oxidation Catalysts. The facility was able to maintain Carbon Monoxide emissions below 2 ppmvd @15%O_2 throughout much of this period, although on a significant number of occasions emissions rose towards 4 ppm @15%O_2 or even higher. These periods of higher emissions were likely the result of low-load or transient load conditions. Gas turbines are typically optimized for full load operation. At partial loads, the combustion efficiency decreases and the firing temperature drops (resulting in incomplete burnout of Carbon Monoxide). When the gas turbine is in transition, the fuel/air ratio is adjusting to the changing firing rate (as fuel lags combustion air flow during a load increase and the combustion air lags fuel flow during a load decrease) resulting in lower combustion efficiency. For the periods where Carbon Monoxide exceeded 4 ppm, the majority (10 of 13) occurred during the first 12 months of operation, indicating that these higher emissions levels were most likely the result of the facility fine-tuning the equipment and optimizing its operating procedures. There were relatively fewer days where emissions exceeded 4 ppm after the first 12 months of operation, indicating that the equipment should be able to keep emissions down to that level on an ongoing basis.

Based on this data, the Air District has concluded that the selected BACT technology should be able to achieve Carbon Monoxide emission rates as low as 2 ppm during some operations, but under some conditions (*e.g.* transient load conditions) will have emission rates up to 4 ppm. The appropriate BACT emissions limit for this equipment is therefore 4.0 ppmvd @15%O_2.

The Air District has also reviewed a number of similar combined-cycle power plants using similar equipment to further evaluate what Carbon Monoxide emissions limit would be achievable for this choice of BACT technology. A summary of the facilities reviewed is set forth in Table 11 below. The table identifies both NOx limits and Carbon Monoxide limits because they are dependent on each other. The lower the NOx limit, the greater leeway must be given in the Carbon Monoxide limit because reducing NOx normally results in increasing Carbon Monoxide.

Table 11:
Recent BACT carbon monoxide permit limits for large combined-cycle combustion Turbines/heat recovery boilers

Facility	NOx ppmvd @15%O2	CO ppmvd @15%O2	Operational Status
Hanging Rock, OH-0252	3 (3-hr)	9 (24-hr)	Unknown
FPL Turkey Point, FL-0263	2 (24-hr)	8 (24-hr)	Unknown
La Paloma, SJVAPCD	2.5 (1-hr)	6 (3-hr)	In Operation

[25] See Metcalf Energy Monthly BAAQMD CEM Reports, from 5/1/2005 to 1/31/2008. The Air District focused on data from days without startup or shutdown activity. When the turbines/heat recovery boilers are starting up or shutting down, Carbon Monoxide emissions are much higher than during steady-state operations as discussed in more detail in subsequent sections. By looking only at data from days without startups or shutdowns, the Air District has ensured that the limit it adopts will be appropriate for steady-state operating conditions.

Table 11: Recent BACT carbon monoxide permit limits for large combined-cycle combustion Turbines/heat recovery boilers			
Facility	**NOx ppmvd @15%O2**	**CO ppmvd @15%O2**	**Operational Status**
Mountainview San Bernadino County	2.5 (1-hr) 2.0 (1-hr) in 2005	6 (3-hr)	In Operation
Three Mountain, Shasta County	2.5 (1-hr)	4 (3-hr)	Not Built
SMUD Clay Station, SMAQMD	2 (1-hr)	4 (3-hr)	Unknown
Elk Hills, SJVAPCD	2.5 (1-hr)	4 (3-hr)	In Operation
Sunset Power, SJVAPCD	2 (1-hr)	4 (3-hr)	Unknown
Palomar Energy Project	2 (1-hr)	4 (3-hr)	In Operation
Sacramento Municipal Utilities District, Consumnes	2 (1-hr)	4 (3-hr)	In Operation
San Joaquin Valley Energy Center	2 (1-hr)	4 (3-hr)	Not Built
Calpine Facility Sutter, Feather River AQMD	2.5 (1-hr)	4 (24-hr)	In Operation
Sierra Pacific Power Company, Tracy Station, NV-0035	2 (3-hr)	3.5 (3-hr)	Unknown
ANP Blackstone, MA-0024	2 (1-hr) No Steam 3.5 (1-hr) Steam Inj.	3.0 (1-hr)	In Operation
Welton Mohawk, AZ-0047	2 (3-hr)	3 (3-hr)	Unknown
Colusa Generating Station	2 (1-hr)	3 (3-hr)	Not Built
Rocky Mountain Energy Center, CO-0056	3.0 (1-hr)	3	In Operation
Turner Energy Center, OR-0046	2.0 (1-hr)	2.0 (3-hr)>70% load, 3.0 (3-hr)<70% load	Not Built
Berrian Energy Center, MI-0366	2.5 (24-hr)	2.0 (3-hr)	Unknown
BP Cherry Point, WA-0328	2.5 (3-hr)	2 (3-hr)	Unknown
Wanapa Energy Center, OR-0041	2 (3-hr)	2 (3-hr)	Not Built
Morro Bay - Duke	2 (1-hr)	2 (3-hr)	Not Built
Goldendale Energy, WA-0302	2 (3-hr)	2 (1-hr)	In Operation
Sumas Energy 2, WA-0315	2 (3-hr)	2 (1-hr)	Not Built
IDC Bellingham, MA	1.5 (1-hr)	2 (1-hr)	Not Built
Magnolia, SCAQMD	2 (3-hr)	2 (1-hr)	In Operation
Southern Company McDonough Combined Cycle, GA-0127	6 (May thru Sept) 15, 30 day Rolling Avg.	1.8 (3-hr)	In Operation
CPV Warren, VA-0308	2 (1-hr)	1.2 to 2.5 (3-hr)	Not Built

Notes: Limits are with duct burners in operation. All projects use gas turbines equipped with Dry Low NO_x combustors. All projects use GE Frame 7FA turbines except Feather River (Siemens 501F), San Joaquin Energy Center (Siemens 501F), ANP Blackstone (ABB GT-24), and La Paloma (ABB GT-24). SCR was utilized for NO_x control at all facilities. Oxidation Catalyst was utilized for CO and POC control at all facilities except Turkey Point., and Hanging Rock.

This review shows that many similar facilities have been permitted with Carbon Monoxide limits of 4.0 ppm, although there are also several facilities that have been permitted with lower limits in the range of 2-3 ppm or even less. Based on all of the evidence that the Air District has reviewed, a limit in the 2-3 ppm range used in some of these permits may not be achievable for the proposed Russell City Energy Center.

First, many of the facilities with very low Carbon Monoxide limits have less stringent NOx limits that the Air District is proposing here. Some of these facilities are allowed to emit NOx at a higher concentration than the 2.0 ppm limit proposed here. Others are allowed to average their emissions over a longer period of time, which allows the facility to exceed the stated numerical limit for a period of time as long as the excess emissions are offset by lower emissions at other times during the averaging period. The Air District is proposing a stringent one-hour averaging period, which together with the 2.0 ppm numerical limit is the most stringent NOx emission limitation of any similar facility that the Air District has identified, as discussed in the previous section.[26] This stringent NOx limit requires some additional flexibility in the Carbon Monoxide limit given the trade-off between NOx reductions and Carbon Monoxide reductions. The more stringent NO_x limit proposed for the Russell City Energy Center makes achieving a 2 ppmvd Carbon Monoxide limit much more difficult.

Second, for the other facilities that have been permitted with a 2.0 ppm NOx limit and a one-hour NOx averaging period, there is little evidence that the facilities would be able to achieve a permit limit of less than 4.0 ppm at low loads and under rapidly-changing load conditions (as explained earlier these operating conditions cause CO emissions to increase). The majority of such facilities with CO permit limits below 4.0 ppm have not been built yet and so there is no operational data on which to evaluate their actual performance under the types of operating scenarios expected for the Russell City Energy Center. Moreover, the BACT determinations that the Air District has reviewed for these facilities do not cite actual data showing that the lower limits are achievable.[27] In light of the evidence showing that emissions will reasonably be expected to be up to 4.0 ppm under some conditions, and without any actual data establishing that a lower limit can consistently be maintained, there is no basis for establishing a BACT limit of less than 4.0 ppm for this facility.

For these reasons, the available data shows that the lowest emissions that these turbines can reasonably achieve using good combustion practices with an oxidation catalyst is 4.0 ppm @15%O_2 (3-hour average). The Air District is therefore proposing this limit as BACT, along with corresponding hourly, daily and annual mass emissions limits. Compliance with these limits will be verified by a continuous emission monitor (CEM) located at the common stack for each gas turbine/heat recovery boiler power train.

3. Best Available Control Technology for Particulate Matter (PM)

[26] As discussed above, the Air District prioritizes NOx over Carbon Monoxide because given the current state of air pollution in the Bay Area, it is more important to reduce NOx emissions in order to address regional ozone pollution (smog) than to address Carbon Monoxide.

[27] *See, e.g.*, Ambient Air Quality Impact Report, Colusa Generating Station, US EPA Region 9 PSD Permit No. SAC 06-01 (May 2008), p. 17.

This Section covers the top-down BACT analysis for Particulate Matter emissions from the combustion turbine/heat recovery boiler power generation trains.

Particulate Matter emissions from this equipment result from several processes. Particulate Matter may be entrained in the combustion air that passes through the combustor inlet filter, and any such Particulate Matter will pass through the combustion chamber and out into the exhaust stream. Trace amounts of Particulate Matter may also be entrained in the natural gas and will also end up in the exhaust stream. In addition, sulfur in the natural gas can form Particulate Matter during combustion, and can also combine with other compounds in the atmosphere after it is emitted to form "secondary" Particulate Matter such as sulfates. Finally, some hydrocarbons in the natural gas may not be fully combusted and may condense to form Particulate Matter. Particulate emissions can vary greatly among different combustion turbines based on factors such as the combustion characteristics of the turbine, the sulfur and particulate content of the natural gas being burned, and the amount of particulates entrained in the combustion air.

STEP ONE: Identify Control Technologies

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

Combustion Controls

Good Combustion Practice: The Air District has identified good combustion practices as an available combustion control technology for minimizing unburned hydrocarbon formation during combustion. Good combustion will ensure proper air/fuel mixing to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of Particulate Matter at the stack.

Clean-burning fuels: The use of clean-burning fuels, such as natural gas that has only trace amounts of sulfur that can form particulates, will result in minimal formation of Particulate Matter during combustion.

Dry Low-NOx Combustor: The use of a Dry Low-NOx Combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable Particulate Matter.

Post-Combustion Controls

Electrostatic precipitators: Electrostatic precipitators are used on solid fuel boilers and incinerators to remove Particulate Matter from the exhaust. Electrostatic precipitators use a high-voltage direct-current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes and deposited on collection plates. Particles are collected and disposed of by mechanically rapping the electrodes and plates and dislodging the particles into collection hoppers.

Baghouses: Baghouses are used to collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

STEP TWO: Eliminate Technically Infeasible Options

Good combustion practice is a feasible control technique for the gas turbines and duct burners in the heat recovery boiler.

The use of natural gas as fuel in a Dry Low-NOx combustor is commercially available and demonstrated for the Russell City Energy Center gas turbines and heat recovery boilers. Low-sulfur natural gas is readily available as a fuel, and Dry Low-NOx combustors are commercially available for this type of application.

Electrostatic precipitators and baghouse systems are not feasible for natural gas-fired combustion turbines and related equipment, however, because they generate a significant backpressure on the exhaust stream. This backpressure would necessitate the use of additional forced draft fans to blow the hot exhaust gases through the particulate control device and out the stack. The additional air introduced into the exhaust stream by such fans would further dilute the particulate concentration in the exhaust stream to such a low level that fabric filters and electrostatic precipitators would be ineffective.[28] Post-combustion particulate control equipment therefore is not feasible for the RCEC turbines.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Low-sulfur natural gas and Dry Low-NOx combustors with Good Combustion Practice are the only feasible control technologies. They can be used in combination with each other, and so they are all ranked No. 1 in terms of control effectiveness. The Air District has determined that the use of these control technologies represents the Best Available Control Technology for Particulate Matter. There are no collateral adverse impacts that would call into question the selection of these technologies as BACT. Because the Air District has chosen the top-ranked control technologies, no further analysis is required under EPA's top-down BACT approach.

Determination of BACT Emissions Limit for Particulate Matter:

For low-sulfur fuel, the highest quality commercially available natural gas is natural gas that meets the California PUC regulatory standard of less than 1.0 grains of sulfur per 100 scf. This PUC standard is maximum sulfur content at any point in time; the actual average content is expected to be less than 0.25 grains per 100 scf. The Air District is therefore proposing a BACT limit for fuel sulfur content of 1.0 grains of sulfur per 100 scf, and 0.25 grains per 100 scf averaged over any 12-month period.

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[28] 0.0013 to 0.01 grains per standard cubic foot. *BAAQMD BACT/TBACT Workbook*, Section 11: Miscellaneous Sources.

The Air District is also proposing a numerical BACT emissions limit for Particulate Matter emissions. The District is proposing a BACT limit of 9 pounds per hour as the lowest reasonably achievable emissions limit based on operating experience and source test results at other plants with similar equipment owned and operated by the applicant. The Particulate Matter emission rate of 9 pounds per hour is equivalent to 0.0040 pounds per million BTUs, 430 pound per day (both trains), and 0.0030 grains per dry standard cubic foot (3% O2).

In establishing this limit, the Air District also looked at the performance of other similar facilities using similar types of equipment and fuel as demonstrated by enforceable permit conditions imposed as BACT limits. The table below presents Particulate Matter BACT limits for projects similar to the proposed Russell City Project.

Table 12:
Recent BACT PM_{10} Permit Limits for large combined-cycle combustion Turbines/heat recovery boilers

Facility	Without Duct Firing		With Duct Firing	
	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)
Wellton Mohawk, AZ-0047			29.8 lb/hr GE 33.1 lb/hr Siemens	
Hanging Rock, OH-0252	15 lb/hr		23.3 lb/hr	
Goldendale Energy Project, WA-0302	19 lb/hr Base Load		22.3 lb/hr Peak	
ANP Blackstone, MA-0024	21.8 lb/hr	0.012	NA	
Colusa Generating Station	20.1 lb/hr	0.0088	20.1 lb/hr	0.0088
Berrian Energy Center, MI-0366	19 lb/hr	0.012	28.9 lb/hr	0.013
La Paloma, SJVAPCD			17.2 lb/hr	
Palomar Energy Project	14 lb/hr		14 lb/hr	
Morro Bay - Duke			13.3 lb/hr	0.0058
Calpine Facility Sutter, Feather River AQMD	9.0 lb/hr	0.0047	11.5 lb/hr	0.0056
San Joaquin Valley Energy Center	9.0 lb/hr		11.5 lb/hr	
CPV Warren, VA-0308	9.9 lb/hr 12.5 lb/hr	0.0045 0.0064	11.3 lb/hr Siemens 17.56 GE	0.0047 0.0072
Mountainview San Bernardino County			11.0 lb/hr	0.0052
SMUD Clay Station, SMAQMD			9 lb/hr	
Sacramento Municipal Utilities District, Consumnes	9.0 lb/hr	0.00483	NA	NA
Metcalf Energy Center, BAAQMD			9.0	0.00452
Delta Energy Center,			9.0	0.00424

Table 12: Recent BACT PM_{10} Permit Limits for large combined-cycle combustion Turbines/heat recovery boilers				
Facility	Without Duct Firing		With Duct Firing	
	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)	PM_{10} Emissions Limit	PM_{10} (lb/MMBtu)
BAAQMD				
Los Medanos Energy Center, BAAQMD			9.0	0.0040
Sumas Energy 2, WA-0315			571 lb/day total	
Sierra Pacific Power Company, Tracy Station, NV-0035			0.011 lb/MMBtu	
IDC Bellingham, MA			0.008 lb/MMBtu	
Rocky Mountain Energy Center			0.0074 lb/MMBtu	
Three Mountain, Shasta County			0.0012 gr/dscf@ 3% O_2	
Magnolia, SCAQMD			0.01 gr/dscf	

Notes: 1. Limits are with duct burners in operation except for SMUD Consumnes and ANP Blackstone which have unfired HRSGs.
2. SCR for NO_x at all facilities.
3. All projects use turbines equipped with Dry Low NO_x combustors.
4. Oxidation Catalyst for CO and POC are utilized at all facilities except Turkey Point, Hanging Rock and Delta Energy Center.

The proposed Particulate Matter emissions limits are as low or lower than the emissions requirements in the table above for similar power plants, except the Three Mountain Power Plants (0.0012 gr/dscf@ 3% O_2). This plant was never built so it is not possible to determine whether it was able to meet the respective Particulate Matter requirement.

4. Best Available Control Technology For Gas Turbine Startups, Shutdowns, and Tuning

Startup and shutdown periods are a normal part of the operation of combined-cycle natural gas-fired power plants. They involve emissions rates that are greater than emissions during steady state operation and are highly variable. Emissions are greater during startup and shutdown for several reasons. One reason is that during startup and shutdown, the turbines are not operating at full load where they are most efficient. Another reason is that the exhaust temperatures are lower than during steady-state operations. Post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function optimally at lower temperatures, and so there may be partial or no abatement for NO_x and Carbon Monoxide for a portion of the startup period.[29]

[29] Note that emission rates of Particulate Matter are not affected by startups and shutdowns and will be the same as for full load operation as during startup and shutdown periods (9 lb/hour for Particulate Matter).

For startups, the duration of the startup depends upon the temperature of the equipment at the beginning of the startup period. Equipment that is already warm will be able to come up to its full operating temperature more quickly than equipment that is started cold. The longest startups occur when the equipment has been down for 3 days or more (a "cold start"), in which case the startup can take up to six hours until the equipment can achieve its steady-state emissions rates. These cold starts are expected to be infrequent, occurring as little as once per year. The majority of startups will occur when the equipment is already warm or hot ("hot starts" and "warm starts"), which will take between 1 and 3 hours for the equipment to come up to its full temperature.

In addition, the facility may need combustor tuning. This is a regular plant equipment maintenance procedure in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the equipment manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst may not be operating during the tuning operation. The proposed facility would be limited to one tuning operation a year.

Because emissions are greater during startups, shutdowns and combustor tuning periods than during steady-state operation, the BACT limits established in the previous sections for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal PSD Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. To do so, the Air District has conducted an additional Top-Down BACT analysis specifically for startups, shutdowns, and tuning periods.

<u>STEP ONE: Identify Control Technologies</u>

The Air District has identified three potential strategies to reduce startup and shutdown emissions for the proposed Russell City facility.

Work practices to minimize emissions: By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions.

Once-Through Steam Boiler Technology*:* Conventional combined-cycle power plants use a thick-walled steam drum in the steam generator to contain the steam before it is introduced into the steam turbine. This steam drum is a major impediment to quicker startups, because its thick steel walls need to be heated slowly and gradually to reduce metal fatigue and ensure long-term safety and reliability of the system. Recently, turbine manufacturers have been utilizing "once-through" boiler technology that does not use the conventional steam drum to contain the steam. These once-through designs (and modified drum designs with the operational characteristics of the once-through boiler) use external steam separators and surge bottles, so they can be brought up to temperature more quickly. Reducing the duration of the startup would reduce startup emissions.

Low-Load "Turn-Down" Technology: Another reason why emissions are increased during startups is that the turbine must spend a certain amount of time operating at less efficient lower loads as it is ramped up to full load. Operating at these lower loads leads to increased emissions. One approach that shows potential for addressing this problem is so-called "turn-down" technology that has been developed to enable turbines to operate more cleanly at lower loads for energy conservation purposes. This technology enables a gas turbine to operate in a standby mode (low capacity) that facilitates a quick ramp-up of capacity to meet electrical demand. The technology uses advanced fuel scheduling (an improved method of controlling fuel distribution) to distribute fuel in the combustor for low turndown operation while maintaining low NOx and CO emissions. It was developed to allow facilities to cut back to lower loads when their power is not needed (typically at night) and still maintain compliance with emissions limits. By cutting back to low load without shutting down completely, the facility can be ready to ramp back up and provide power immediately when demand requires (the next morning, for example). In principle, this same approach should be applicable to startup emissions as well: better performance at low load should be able to reduce emissions during the portions of the startup when the turbine is in low-load operation. As explained below, however, turn-down technology has been applied in startup applications only very recently and its use as a startup control technology is still developing.

STEP TWO: Eliminate Technically Infeasible Options

Using **best work practices** to keep startups and shutdowns as short as possible is a feasible way of minimizing emissions during these periods.

Once-Through Boiler Technology is also a technically feasible control technology. Siemens, the manufacturer whose equipment is proposed for the Russell City Energy Center, has developed a once-through design that it uses in what it calls a "Fast Start" system.[30] The proposed facility could implement Siemens Fast Start technology by installing a Siemens "Flex Plant 10" integrated plant using a single-pressure heat recovery boiler and steam turbine.[31] The single-pressure heat recovery boiler is optimized for peaking plants, however, and not for combined-cycle baseload plants such as the proposed Russell City facility. Those facilities normally use a triple-pressure heat recovery boiler and steam turbine, which is more energy efficient. The single-pressure design operates at an efficiency of approximately 48%, whereas the triple-pressure design can achieve an efficiency of approximately 56%, making it nearly 17% more energy efficient. Siemens is working on developing a triple-pressure system using Fast-Start technology, "Flex Plant 30", but it is still under development, and has not yet been proposed for any power plant projects.[32] The only technically feasible once-through technology at this point is the single-pressure design, which is inherently less efficient.

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[30] M. McManus, D. Boyce, R. Baumgartner, Siemens Power Generation, Inc., *Integrated Technologies that Enhance Power Plant Operating Flexibility*, POWER-GEN International 2007, December 11-13, 2007.

[31] Note that the project was originally permitted in 2002, before Fast Start technology was developed, and the applicant purchased its equipment at that time based on the initial permits. Retrofitting that equipment now to incorporate Fast Start technology would require a complete redesign of the project and the purchase of new equipment. Furthermore, Siemens stated that emissions performance cannot be guaranteed unless the company supplies a fully integrated power plant with Fast Start technology (*i.e.* Flex Plant 10). (Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.) It therefore appears that the facility would have to dispose of the equipment it has already purchased for the project and buy an entirely new integrated system.

[32] Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.

Turn-Down Technology is a fairly new development in turbine technology, and only very recently have attempts been made to adapt it to reducing startup emissions (as opposed to using it to allow low-load operation). Siemens, whose equipment is being proposed for the Russell City Energy Center, is developing a low-load operation flexibility (LLOF) system for its turbines, but it has not yet been validated and is not commercially available at this time.[33] GE, another turbine manufacturer, has a commercially available turn-down technology which it calls "OpFlex",[34] but the company has only just developed a variant aimed at controlling startup emissions. GE calls this adaptation the "OpFlex™ Start-up NOx Start-up Fuel Heating" package. GE claims that emissions of NOx may be lowered to less than 25 ppm NOx at low load operation (20% to 50% load),[35] and that "start-up times can be reduced by as much as 30 minutes for a cold start, 15 minutes for a warm restart and 5 minutes for a hot restart".[36] These are highly encouraging predictions, but GE is not prepared to guarantee these numbers, or any specific level of emissions reductions, for the product at this time.[37] Without a manufacturer guarantee, the Air District cannot conclude with any certainty that this technology will obtain the predicted reductions. Predictions of potential performance are not, by themselves, sufficient evidence on which to require this technology as BACT.

To make up for the lack of a manufacturer's guarantee, the Air District attempted to develop independent objective support for the technology's feasibility as a startup control alternative. To do so, the Air District looked for actual operating data from facilities using GE's OpFlex turn-down technology as a startup emissions control technology. The Air District was able to identify only one facility that has tried to implement OpFlex to control startup emissions, the Palomar Energy Center ("Palomar") in San Diego County.[38] That facility was required to implement drastic startup emissions reductions under a variance proceeding before the Hearing Board of the local Air District, the San Diego Air Pollution Control District.[39] The facility took several steps in order to do so. One of these was to purchase and install an OpFlex system from GE. Another was to adjust its ammonia injection procedures so that ammonia is injected into the SCR system earlier in the startup than recommended by the manufacturer, when the SCR catalyst is at a lower temperature. The operator conducted tests on its turbines and found that for its particular equipment, earlier ammonia injection was a workable solution. By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques.[40] It is not possible, however, to

[33] See P. Nag, D. Little, D. Teehan, K. Wetzl & D. Elwood, Siemens Corporation, *Low Load Operational Flexibility for Siemens G Class Gas Turbines*, to be presented at the Power-Gen International, Orlando, Florida, December, 2008.

[34] GE Fact Sheet for OpFlex™ Turndown, GE Energy website: www.gepower.com.

[35] GE Fact Sheet for OpFlex™ Start-up NOx and Start-up Fuel Heating, GE Energy website: www.gepower.com.

[36] *Gas Turbine Upgrades for Enhancing Operational Flexibility*, EPRI, Palo Alto, CA: 2007, 1012720, at 2-17, available at: http://mydocs.epri.com/docs/public/000000000001012720.pdf.

[37] GE has declined to give emissions performance guarantees for start-up operations using the OpFlex™ software, explaining that startup emissions, by nature, are highly variable and dependent on specific plant equipment and configuration. (Telephone conversations with Bob Bellis and Derrick Owen, GE Energy on November 21, 2008.)

[38] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Nonapplicability Confirmation for Installation of Tuning Software". Submitted to Dan Speer, San Diego County Air Pollution Control District, dated August 22, 2006. The Air District found no other facilities other than Palomar using OpFlex to control startup emissions.

[39] *See* San Diego Air Pollution Control District Hearing Board Docket No. 4703.

[40] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Hearing Board Variance 4073; Quarterly Report". Submitted to Catherine Santos, Clerk of the Hearing Board for the San Diego County Air Pollution Control District, dated April 11, 2007.

determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. For all of these reasons, the Palomar data does not sufficiently demonstrate that there are specific, achievable emissions reductions to be gained simply from using the OpFlex technology itself. Further data will be needed to understand whether some or all of Palomar's proprietary approach for reducing emissions from its equipment can be adapted to other facilities.

Finally, the Air District also looked for other BACT determinations for similar facilities to see whether any other permitting agencies have required OpFlex or similar turn-down technologies to reduce startup emissions. The Air District did not find any BACT determinations where an agency required this type of technology. One permitting agency, EPA Region 9, has considered whether it should be required as BACT, but concluded that it should not.[41]

In summary, the Air District looked to manufacturer guarantees, to actual data from similar facilities, and to permitting actions by other agencies, but has not found sufficiently strong evidence to conclude that turn-down technologies such as OpFlex are technically feasible at this time for control of start-up emissions. While it appears that the technology may have potential for use in reducing startup emissions, the manufacturer cannot guarantee any emissions reductions for such an application. Moreover, OpFlex has been used as a startup control technology at only one facility, and it is not clear whether and to what extent it achieved any reductions, as opposed to other changes the facility made to its proprietary operating procedures for its specific equipment. In addition, EPA has recently determined that the technology is not sufficiently developed as a startup control technology to be required as BACT. For all these reasons, the Air District has concluded that OpFlex and similar low-load turn-down technologies are not technically feasible for use in reducing startup emissions at this time. The Air District will continue to monitor the development of this technology, however, to see whether it may have potential in the future to be required as a mandatory enhancement of power plants' startup emissions control strategies.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Once-through boiler technology would shorten startup times and reduce startup emissions, and so it is ranked No. 1 in control effectiveness. Siemens stated that the Flex Plant 10 could synchronize to the grid in 5 minutes and produce 150 MW on line in 10 minutes; the combustion turbine can achieve emissions compliance in 12 minutes and stack compliance in 20 minutes.

Best work practices can keep startup times below 3 hours for warm and hot startups, and below 6 hours for cold startups. This alternative is ranked No. 2 in control effectiveness because it would result in longer startup periods and therefore additional startup emissions.

[41] *See* Ambient Air Quality Impact Report, Colusa Generating Station, Clean Air Act PSD Permit No. SAC 06-01, EPA Region 9, May 2008. The record from that permitting action shows that EPA Region 9 considered OpFlex and the Palomar facility in response to a comment on the startup BACT issue. That comment was subsequently withdrawn and so EPA never responded to it formally on the record. But the fact that the agency determined that BACT does not require OpFlex is evident from the fact that the permit does not require it.

STEP FOUR: Evaluate Most Effective Controls and Document Results

To determine whether to require once-through boiler technology as BACT, the Air District evaluated its ancillary economic, environmental and energy impacts.

The primary ancillary impacts arise from decreased energy efficiency. As noted above, the only type of once-through boiler technology that is technically feasible at this time is a single-pressure system, the Siemens Flex Plant 10. Combined-cycle turbines with a steam drum design use a triple-pressure system, meaning that steam is introduce into the steam turbine at three different pressures at different point in the turbine, improving electrical output and enhancing efficiency. Requiring a once-through design would eliminate the possibility of using a triple-pressure system.

To evaluate the adverse impacts of this loss in energy efficiency, the Air District compared emission rates from the proposed Russell City Energy Center with its triple-pressure design to those predicted for a proposed facility using a Flex Plant 10 design.[42] The proposed Russell City project will have an energy efficiency of 55.8%,[43] whereas the Flex Plant 10 design will have an efficiency of only 48%. This loss in efficiency means that the Flex Plant 10 design will need to burn more fuel to produce the same amount of power output, which will generate greater emissions. The difference in emissions per unit of power generated is shown below in Table 13.

Table 13: Comparison of Emissions Per Unit of Power Generated (lb/MW-hr)

	NOx	CO	POC	PM	SO_2	CO_2
Flex Plant 10	0.0609	0.0748	0.0108	0.0359	0.0224	936.75
Triple-Pressure System	0.0517	0.0629	0.0090	0.0298	0.0195	796.47
Emissions Increase:	17.92%	18.91%	20.40%	20.34%	14.76%	17.61%

These emissions increases are a substantial drawback from an environmental perspective. Significantly, they are increased environmental impacts that will occur at all times when the facility is operating, including normal base-load operation. This is an important fact in evaluating the trade-offs from requiring a Flex Plant 10 design to improve startup operation. Startups occur occasionally and any benefits in startup mode will be obtained only during startup, whereas the ancillary environmental impacts will occur during all periods of operation. The loss in energy efficiency is also an adverse energy-related impact, as less energy will be generated from the same amount of fuel. The technology would also have an adverse economic impact due to the cost of increased fuel usage.

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[42] Data for the Flex Plant 10 comparison come from a permit application the Air District has received for a facility proposing to use a Flex Plant 10 design, District Application #18542. The proposed Flex Plant 10 facility will have a heat input capacity of 1857 MMBtu/hr. The District adjusted the proposed Russell City project's emissions numbers proportionally to the capacity difference between the two facilities to achieve an "apples-to-apples" comparison. Calculations assume ISO standard conditions and 59°F. Data for Russell City assume no supplemental duct burner firing, because the proposed Flex Plant 10 does not use duct burners.

[43] *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4.

For all of these reasons, the Air District has eliminated the once-through boiler alternative as an appropriate BACT technology for startup emissions for a facility such as Russell City. The Air District has concluded that the adverse impacts of requiring a single-pressure steam turbine design outweigh the additional startup benefits that can be achieved. The Air District will continue to monitor the development of once-through boiler technologies, in particular the Siemens Flex Plant 30 design using a triple-pressure steam boiler. Such future developments could change the analysis regarding the tradeoffs between overall energy efficiency and startup performance.

In contrast to current once-through boiler designs, best work practices have no adverse economic, energy, or environmental impacts that would rule it out as a BACT control technology. The District selects this alternative as BACT for startup emissions for this proposed project.

STEP FIVE: Select BACT

Based on the foregoing analysis, the Air District has concluded that once-through boiler technology would not be the most appropriate BACT technology because of the loss of efficiency that it would entail. The Air District has therefore eliminated it as a control option, and selects best work practices as BACT for startups, shutdowns and tuning.

Determination of BACT Emissions Limit for Startups, Shutdowns and Tuning Events:

The Air District has concluded that using best work practices, the proposed Russell City Energy Center will be able to limit cold startups to 6 hours in duration, 480 pounds of NO_2 emissions, and 5028 pounds of CO emissions; warm and hot startups to 3 hours in duration, 125 pounds of NO_2 emissions, and 2514 of CO emissions; and shutdowns to 30 minutes in duration, 40 pounds of NO_2 emissions, and 90 pounds of CO emissions. The basis for these limits are the permit limits that were established for the Metcalf Energy Center, the most recent similar facility that the Air District has permitted. The Air District began with those limits as a starting point, and then examined data and permit conditions from other facilities to determine if lower limits could be reasonably achieved by this facility. In some instances, recent experience has shown that more stringent limits than were imposed at Metcalf are appropriate. In other cases, more stringent limits would not be achievable.

Cold Startups

The Air District examined data from a number of other similar facilities to determine if cold startups could achieve less than 6 hours in duration, 480 pounds of NO_2 emissions, and 5028 pounds of CO emissions. The data showed a very large amount of variability, which is caused by a number of reasons. The factors that can make individual startups take longer or shorter and generate more or less emissions include ambient temperatures of the equipment, limitations on the loading sequence prescribed by the gas turbine manufacturer to assure safe loading of the equipment, and limitations on the steam-cycle side of the facility necessary to ensure that the steam turbine and associated piping are safely warmed.

The Air District examined startup data from the Sutter Energy Center, which is located in Yuba City and also uses Siemens/ Westinghouse F-class gas turbines, for the past two calendar years. The data for cold startups are set forth below in Table 14. As the table shows, a number of startups have had

NO_2 emissions close to or even above the proposed 480 pound limit for the Russell City facility. Several of the startups have taken all or nearly all of the full 6 hours proposed for Russell City.

Table 14: Sutter Energy Center Cold Start-Up Event Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
1/8/2007	2	314	399	872
4/16/2007	2	300	385	233
4/23/2007	2	264	328	1034
4/23/2007	1	300	346	415
1/6/2008	1	325.2	480	1454
3/5/2008	2	360	499	1129
4/2/2008	2	351	392	914
5/12/2008	1	265.2	425	1576
5/12/2008	2	324	488	1181
6/23/2008	1	265.8	271	1084

Data for the Delta Energy Center, shown in Table 15 below, have shown lower NO_2 emissions, but greatly increased CO emissions. Two of the startups involved emissions considerably over the 5028 pound limit being considered for Russell City. The longest startup was 4.5 hours.

Table 15: Delta Energy Center Cold Start-Up Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
5/23/2004	1	269	262	3225
5/22/2005	2	231	281	8288
4/17/2006	1	86	152	1202
5/16/2006	2	108	189	3198
4/28/2007	1	175	156	7298
6/5/2008	3	123	119	2599

Data for the Metcalf Energy Center, set forth in Table 16 below, show emissions below both the proposed NO_2 limit and the proposed CO limit, although not with a great safety margin. NO_2 emissions have been up to 70% of the proposed limit, CO emissions have been up to 95% of the proposed limit, and startup duration has been up to 99% of the proposed limit.

Table 16: Metcalf Energy Center Cold Start-Up Summary

Date	Unit	Duration (min)	Total NOx (lbs)	Total CO (lbs)
4/1/2006	2	187	270	4792
5/1/2006	1	358	335	3110
5/8/2006	2	199	232	2686
6/14/2006	2	160	205	3430
5/13/2008	1	98	125	1998
6/2/2008	2	122	129	3022
6/2/2008	1	95	123	2023
6/9/2008	1	86	103	1926
11/24/2008	1	294	151	4429

Finally, data from the Los Medanos Energy Center, set forth in Table 17 below, shows emissions close to the proposed 480 pound NO_2 limit on a number of occasions (with even one slight exceedance), although CO emissions are much lower.

Table 17: Los Medanos Energy Center Cold Start-Up Summary				
Date	**Unit**	**Duration (min)**	**Total NOx (lbs)**	**Total CO (lbs)**
11/24/2004	2	190	453	117
11/13/2006	2	245	421	116
5/23/2007	2	88	172	25
3/18/2008	1	215	485	67

The data the Air District has evaluated suggest that it would not be appropriate to reduce the emissions limits for the proposed Russell City Energy Center below the limits adopted for the Metcalf facility as a mandatory BACT limit. Although some turbines on some occasions have achieved lower emissions rates, the BACT limit must be achievable at all times throughout the facility's operational life. A reasonable safety margin must be included so that the facility will be able to comply with its limits during every startup, even if emissions for specific startups or as an average for startups as a whole may be less. The data from other similar facilities shows that if the Air District were to impose limits substantially below the Metcalf limits, the proposed facility could face difficulty in complying with them. The Air District is therefore proposing to require the same cold startup BACT emission limits as the Metcalf Energy Center: 6 hours total duration, 480 pounds of NO_2, and 5028 pounds of CO.

Hot/Warm Startups

For hot and warm startups, the Air District has concluded that the proposed Russell City facility would be able to achieve emissions limitations substantially below those imposed at Metcalf. Calpine has refined its hot and warm startup operations based on its experience with other facilities, and has committed to keeping hot and warm startup emissions below 125 pounds of NO_2. This emissions level represents a reduction of nearly half from the corresponding Metcalf startup limit, which is 240 pounds. Calpine has committed to this substantial reduction based upon its assessment of its record controlling NO_x emissions during start-up events, as demonstrated by data from its other facilities. Further, although there is normally a trade-off between decreased NOx emissions and increased CO emissions as discussed above, Calpine has committed to achieving the proposed NOx reductions while maintaining CO emissions at the same level adopted for the Metcalf facility (2,514 pounds per event).

Shutdowns

The proposed Russell City facility should be able to achieve significantly reduced shutdown emissions as well. As with hot and warm startups, Calpine has refined its shutdown procedures and has committed to maintaining NO_2 emissions below 40 pounds per shutdown, half the emissions limit imposed at Metcalf, while not increasing its CO emissions.

Tuning Events

Tuning events are expected to be similar in nature to cold startup events, in that they may take up to six hours to complete, may involve operation at low loads where emissions efficiency is compromised, and may require operation without pollution control equipment such as the SCR system. In addition, like cold startups tuning events are expected to occur relatively infrequently, and will be limited to one event per year. For these reasons, the achievable emissions rates for tuning events are expected to be similar to those for cold startups. The Air District is proposing to require emissions during tuning events to comply with the cold startup conditions as the BACT emissions limit.

Conclusion

The Air District is proposing the most stringent emission limits for startups, shutdowns, and tuning event that can reasonably be achieved by the proposed Russell City Energy Center, based on a review of actual operating data and experiences from similar facilities. Emissions from specific startup, shutdown and tuning events may be significantly less than the proposed not-to-exceed permit limits, and the average of all such events is likely to be less than the maximum allowable levels, given the great variability of such events. The District is proposing to require the limits described above as the enforceable BACT limits to ensure that emissions are minimized to the greatest extent feasible while ensuring that the limits are achievable under all operating circumstances.

5. Best Available Control Technology During Commissioning

The combustion turbine/heat recovery boiler equipment is highly complex and has to be carefully tested, adjusted, tuned and calibrated after the facility is constructed. These activities are generally referred to as "commissioning" of the facility. During the commissioning period, each of the combustion turbine generators needs to be fine-tuned at zero load, partial load, and full load to optimize its performance. The dry-low NOx combustors also need to be tuned to ensure that the turbines run efficiently while meeting both the performance guarantees and emission guarantees. The heat recovery boiler and steam pipes also need to be steam-cleaned to ensure that no manufacturing or construction materials or debris that could damage the steam turbine remains within the heat recovery boiler or steam pipes. In addition, the selective catalytic reduction (SCR) systems and oxidation catalysts need to be installed and tuned.

The combustion turbine/heat recovery boiler trains will not be able to meet the stringent BACT limits for normal operations during the commissioning period, for a number of reasons. First, the SCR systems and oxidation catalysts cannot be installed immediately when the turbines are initially started up. There may be oils or lubricants in the equipment from the manufacture and installation of the equipment, which would damage the catalysts if they were installed immediately. Instead, the turbines need to be operated without the SCR systems and oxidation catalysts for a period of time to burn off any impurities that may be left in the equipment. In addition, once all of the pollution control equipment is installed, it needs to be tuned in order to achieve optimum emissions performance. Until the equipment is tuned, it will not be able to achieve the very high levels of emissions reductions reflected in the stringent BACT limits for normal operations.

Because the BACT limits established for normal operations are not technically feasible during the commissioning period, these limits are not "achievable" during this period and are not "Best Available Control Technology" as defined in the Federal PSD Regulations. Alternate BACT limits must therefore be specified for this mode of operation. To do so, the Air District has conducted an additional Top-Down BACT analysis specifically for the required commissioning activities.

The only control technology available for limiting emissions during commissioning is to use best work practices to minimize emissions as much as possible during commissioning, and to expedite the commissioning process so that compliance with the stringent BACT limits for normal operations can be achieved as quickly as possible. There are no add-on control devices or other technologies that can be installed for commissioning activities. Best work practices are a feasible method of limiting emissions as much as possible, however, and so it is the top (and only) control option for purposes of a top-down BACT analysis. There are no energy, environmental or economic impacts that would make this option inappropriate as the BACT control technique, and so the Air District is proposing best work practices as BACT for the commissioning period.

To implement best work practices as an enforceable BACT requirement, the Air District is proposing conditions that will require the facility to minimize emissions to the maximum extent possible during commissioning. The Air District is also proposing numerical emissions limits based upon the equipment manufacturer's best estimates of uncontrolled emissions at the operating loads that the facility will experience during commissioning. The proposed permit conditions will limit emissions to below the following levels:

Table 18: Commissioning Period Emissions Limits		
Air Pollutant	**Proposed Commissioning Period Emissions Limits**	
NO_2	4805 lb/day	400 lb/hr
Carbon Monoxide	20,000 lb/day	5000 lb/hr
PM_{10}	432 lb/day	

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

The Air District is also proposing permit conditions to minimize the duration of commissioning activities. The proposed conditions require the facility to tune the combustion turbine/heat recovery boiler trains to minimize emissions at the earliest feasible opportunity; and to install, adjust and operate the SCR systems and oxidation catalysts at the earliest feasible opportunity. The Air District is also proposing to cap the total amount of time that each turbine can operate without the SCR systems and oxidation catalysts at 300 hours. This limit represents the shortest amount of time in which the facility can reasonably complete the required commissioning activities without jeopardizing safety and equipment warranties. The proposed 300-hour limit is based on the following estimates of the time it will take for each specific commissioning activity.

Table 19: Commissioning Schedule	
Commissioning Activity	**Estimated Duration**
First Fire of the combustion turbine, testing, synchronizing during: • Full Speed No Load operation • CTG load test, bypass valve and safety valve tuning	36 hours
Steam blows of the steam piping • HRSG tuning • HRSG restoration and install SCR/CO catalyst	114 hours
Tuning of combustion turbine up to 40% load	12 hours
Run unit at low load to get steam quality for rolling the steam turbine • Establish vacuum/ HRSG tuning • By-pass operation/steam turbine initial roll and trip test • By-pass operation steam turbine load test • Combined cycle drift test • Emissions tuning/drift test	72 hours
Initial roll of the steam turbine • CTG on by-pass/steam turbine load test	10 hours
Tune SCR and CO Catalyst-ammonia calibration	19 hours
Cal-ISO certification	30 hours
Contingency	16 hours
TOTAL:	300 hours

The Air District also reviewed commissioning times for other similar facilities to verify these estimates. Calpine's Delta Energy Center, which began operation in 2002, completed commissioning for its three turbines in 96, 296, and 207 hours, respectively, indicating that 300 hours is an appropriate limit. In addition, the wide variation in the number of hours required to commission these three turbines highlights the unpredictability inherent in commissioning any individual turbine system. This unpredictability underscores the importance of allowing sufficient time to ensure that all required commissioning activities can be completed. The Air District also reviewed permit limits from other recent power plant projects in the Bay Area, several of which had commissioning period limits of 500 hours. The project applicant is confident that it can complete commissioning in 300 hours, however, based upon its extensive experience commissioning similar combustion turbines, which will allow it to conduct the commissioning process more efficiently.

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

B. Cooling Tower

Cooling towers are heat removal devices used to remove excess heat from the facility's cooling system. The Russell City Energy Center is proposing to use a wet cooling tower system in which water is circulated through a condenser to absorb the heat from the steam produced by the steam turbine. The condensed water is then circulated through the cooling tower where some of it is evaporated, removing excess heat. The cooling water is then returning to the condenser by a re-circulating pump.

Cooling towers can cause small amounts of Particulate Matter emissions from solids, commonly referred to as Total Dissolved Solids (TDS), in the cooling water. As the cooling water is circulated through the tower, water droplets known as "drift" can become entrained in the air stream and leave the cooling tower into the atmosphere. Solids in the drift droplets can then become Particulate Matter emissions.

STEP 1: Identify Control Technologies

High-efficiency drift eliminators: High-efficiency drift eliminators are commonly used in cooling towers to control the Particulate Matter emissions. These devices collect drift droplets contained in the air exiting the cooling tower and return them to the water in tower. High efficiency drift eliminators can control the drift to less than 0.0005 percent (0.5 gallons per 100,000 gallons of flow) of the cooling tower circulating water flow. Drift eliminators are able to capture nearly 100 percent of the droplets which are larger than 10 microns ("µm") in diameter. The Air District has not identified any other control technologies for reducing cooling tower drift.

STEP 2: Eliminate Technically Infeasible Options

High-efficiency eliminators have been demonstrated on many power plant installations. The technology is technically feasible and available for the cooling tower proposed for the Russell City Energy Center.

STEP 3: Rank Remaining Control Technologies by Control Effectiveness

As the only available control technology, the Air District ranks the No. 1 control technology for cooling tower emissions. The Air District has found no collateral environmental, economic, or energy impacts that would suggest that this is not an appropriate control technology, and so it has determined that the use of high-efficiency drift eliminators is BACT control technology. As the Air District has selected the top control technology for the project, no further top-down analysis is required.

Determination of BACT Emissions Limit for Cooling Tower Emissions:

It is not feasible to implement a limit on cooling tower Particulate Matter emissions directly, as the solids that form the Particulate Matter are contained within the water droplets emitted in the drift. Instead, the Air District proposes a limit on the amount of drift itself as a surrogate for Particulate Matter emissions. The amount Particulate Matter emitted from the cooling tower will be proportional to the amount of drift, and so limiting drift is an appropriate means of limiting Particulate Matter.

High-efficiency drift eliminators can reliability achieve a drift rate of less than 0.0005%.[44] The Air District has examined permit limits from 13 other similar facilities using high-efficiency drift eliminators on wet cooling towers, and found that they all have limits of 0.0005%.[45] The Air District is therefore proposing 0.0005% cooling tower drift as the BACT limitation for Particulate Matter for this source.

C. Emergency Fire Pump Engine

The proposed Russell City Energy Center will require an emergency diesel fire pump engine to be used in case of emergency to provide water to fight fires. The fire pump engine would be used solely to pressurize a fire suppression system. It would be operated only in case of emergency, as well as for short periods for inspection, maintenance, and testing, as required by the standards of the NFPA to ensure reliability in case of fire.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x including NO_2), hydrocarbons, Carbon Monoxide, and Particulate Matter (including both visible (smoke) and non-visible emissions). Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants (hydrocarbons, Carbon Monoxide, and Particulate Matter) are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust.

[44] Source test results for Metcalf Energy Center.
[45] The 13 facilities are: PICO-Von Raesfeld Power Plant; Inland Empire Energy Center; Tesla Energy Center; Vineyard Energy Center-Utah; Blythe Energy Center; Delta Energy Center; Rio Linda Power Plant; Las Vegas Cogen; East Altamont Energy Center; Mission-Sun Valley; Mission-Walnut; Pastoria Energy Center; and Liberty Energy V, XX, and XXIII.

The Air District has undertaken the following BACT analysis for NO_2, Carbon Monoxide and Particulate Matter for the diesel fire pump engine in accordance with EPA's PSD permitting guidelines.[46]

STEP ONE: Identify Control Technologies

The Air District has identified three primary types of control technologies that could potentially be used to reduce air pollutant emissions from the diesel fire pump engine: the use of clean diesel fuel; combustion technologies to limit pollutant formation during combustion; and post-combustion technologies that remove pollutants that are formed before they can enter the atmosphere.

Clean Fuel Technologies:

Recent advances in diesel fuel formulation technology can help reduce emissions when the fuel is combusted in diesel engines. Such technologies include the following:

Ultra-Low Sulfur Fuel: The use of diesel fuel that meets the CARB ultra-low sulfur diesel fuel standard (< 0.015% by weight sulfur) can reduce the amount of Particulate Matter and NO_2 formed during combustion. Reducing the amount of sulfur in the fuel reduces the amount of Particulate Matter generated because the sulfur in the fuel is mostly converted into sulfur dioxide during combustion, which reacts with water to form sulfuric acid, a particulate that contributes to total Particulate Matter emissions. An ultra-low sulfur diesel fuel will limit the amount of sulfur that forms PM emissions. In addition, using ultra-low sulfur fuel reduces NO_2 emissions because the hydro-treating technique used to remove the sulfur from the diesel fuel also removes nitrogen, leaving only trace amounts. Reducing the amount of nitrogen in the fuel reduces the amount of nitrogen available to form NO_2 during combustion.

Fuel Additives: The procedure broadly defines fuel additives to be substances that are present in cylinder during combustion for any of a number of different purposes, such as decreasing emissions or assisting in the operation of another diesel emission control system. One common type of fuel additive, known as a "fuel borne catalyst" (FBC), is routinely used in several countries in Europe to assist in the regeneration of DPFs. FBCs are metallic in nature (e.g., cerium, iron, and platinum) and are added in low concentrations to diesel fuel. Particles of the FBC get associated with soot particles during the combustion process and significantly lower the soot combustion temperature.

Combustion Technologies:

There are also a number of design features that can be used for diesel engines that can reduce the amount of air pollutants generated during combustion of the fuel, including NO_2, Carbon Monoxide and Particulate Matter. These features include:

Turbocharging: A turbocharger is an exhaust gas-driven air compressor used for forced-induction of an internal combustion engine. The purpose of a turbocharger is to increase the mass of air entering the engine to create more power. Turbocharging decreases emissions due to increased efficiency (less fuel is combusted to achieve the same output without turbocharging). Turbochargers

[46] Note that this diesel engine is also subject to stringent regulations under California law over and above the federal regulations under the Federal PSD Program. *See California Code of Regulations section 93115*

reduce both NOx and PM emissions by approximately 33 percent when compared to naturally aspirated engines.

Intercooler: An intercooler, or charge air cooler, is an air-to-air or air-to-liquid heat exchange device used on turbocharged internal combustion engines to increase the intake air charge density through cooling. A decrease in air intake temperature provides a denser intake charge to the engine and allows more air and fuel to be combusted per engine cycle, increasing the output of the engine.

Retarding Injection Timing: Retarding the injection of fuel into the engine reduces the peak flame temperature, which improves NOx emission but typically results in higher PM emissions. The fuel starts combustion at the point when it is injected into the cylinder. Retarding the timing of the fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NOx formation. Retarding the injection timing reduces NOx from all diesel engines; however, the effectiveness is specific to each engine model. Moreover, retarding injection decreases the horsepower output of the engine. The amount of NOx reduction with ITR diminishes with increasing levels of retard.

Exhaust gas recirculation (EGR): Exhaust gas recirculation allows a controlled portion of spent combustion gases to circulate back into the intake system where it mixes with pre-combustion air. The exhaust serves as a diluent to lower the in-cylinder oxygen concentration and also to increase the heat capacity of the air/fuel mixture. This reduces peak combustion temperature and the rate of combustion, thus reducing NOx emissions. Typical NOx reductions achieved by EGR retrofits are about 40 to 50 percent.

Pre-Combustion Chamber: A precombustion chamber is a prechamber in the engine that ignites a fuel-rich mixture that propagates into the main combustion chamber where additional air is introduced to make the air/fuel mixture lean. The high exit velocity from the precombustion chamber results in improved mixing and complete combustion of the lean air/fuel mixture, which lowers combustion temperature, thereby reducing NOx emissions.

Post-Combustion Controls:

Finally, there are several post-combustion technologies that could potentially be used to remove emissions from the diesel firepump engine's exhaust before they are emitted to the atmosphere.

Selective Catalytic Reduction Systems: Selective catalytic reduction (SCR) systems are a form of after-treatment technology that use a reagent, typically ammonia or urea, to convert NOx to nitrogen and oxygen over a catalyst. SCR is described in detail above in connection with the combustion turbine/heat recovery boiler BACT analysis (*see* Section V.A.1 above). SCR requires exhaust temperatures to be between 250 and 450 degrees Celsius in order to work properly.

Lean-NOx Catalyst: Another after-treatment based NOx control technology is referred to as the lean-NOx catalyst. Similar in principle to an SCR system, a Lean-NOx Catalyst system relies on injection of a reagent upstream of the catalyst to reduce NOx emissions.

NOx Adsorbers: NOx adsorbers, also called NOx traps, are one of the newest emission control strategies under development. They employ catalysts to which NOx in the exhaust stream adsorbs when the engine runs lean. After the adsorber has been fully saturated with NOx, the system is regenerated with released NOx being catalytically reduced when the engine runs rich. NOx reductions in excess of 80-90 percent have been reported. A prerequisite for proper functioning of this new technology is low-sulfur fuel (to prevent fouling of the catalyst).

Diesel Oxidation Catalyst: A diesel oxidation catalyst uses a very light loading of platinum catalyst to oxidize compounds such as Carbon Monoxide and many of the hydrocarbons that condense into droplets and form Particulate Matter upon leaving the exhaust system and entering the atmosphere. Diesel oxidation catalysts are typically able to reduce PM emissions by about 25 percent. However, they do not reduce the solid soot particles in PM by any appreciable amount.

Diesel Particulate Filters: Diesel particulate filters are more effective at reducing emissions of Particulate Matter than diesel oxidation catalysts. This technology uses a filter medium such as a porous ceramic or sintered metal material that permits gases in the exhaust to pass through but traps the Particulate Matter. These filters are very efficient in reducing Particulate Matter emissions, typically achieving reductions in excess of 85 percent.

Fabric Filter Baghouses: Baghouses collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

STEP TWO: Eliminate Technically Infeasible Options

Clean Fuel Technologies:

Ultra-low sulfur Diesel fuel is available and demonstrated for stationary compression ignition engines. It is technically feasible for the fire pump engine.[47] The use of fuel additives is still in a developmental stage in the United States, however, and is not commercially available. Fuel additives are not technically feasible for the fire pump engine

Combustion Controls:

The design of a diesel engine – including the choice of combustion technologies to reduce the formation of air pollutants during combustion – is determined by the manufacturer of the engine, not by the end-user. Diesel engine users, such as the Russell City Energy Center here, are limited to the engines that are commercially available from manufacturers. The determination of what combustion control technologies are technically feasible must therefore focus on what technologies are commercially available to be purchased for this project.

The technologies that are commercially available are those that manufacturers are using to achieve the EPA Tier 2 requirements for engines of the class needed for emergency fire service at the Russell City Energy Center.[48] There are no Tier 3 or Tier 4 engines currently available that can serve the facility's emergency fire service needs.

Post-Combustion Controls:

[47] Under CARB regulations, the emergency fire pump engine will use only California ultra-low sulfur Diesel fuel when operating.
[48] December 18, 2006 Clarke Letter; South Coast AQMD - Tier 3 direct drive fire pump engines are not available.

Post-combustion controls are not feasible for direct-drive fire pump engines of the type needed to serve the emergency fire suppression needs of the Russell City Energy Center.[49] Addition of a catalytic device to the exhaust system would be technically infeasible, due to the variable load of the engine and the nature of the control system. Injection of a reagent into the engine exhaust to control pollutants (mainly NO_x) is dependent on a constant steady state engine load. But the fire pump engine will need to operate effectively under highly variable loads, thus ruling out this type of control technology. Installation of other after-treatment devices such as particulate traps will also compromise reliability, performance, and safe operation of the fire pump.[50]

In addition, the use of post-combustion control technologies would be incompatible with the fire pump's role as a safety device for use in emergencies. Direct-drive fire pump engines of the type proposed for the Russell City Energy Center are designed differently than other stationary or off-road diesel-fueled engines. Direct-drive fire pump engines must meet the stringent National Fire Protection Association (NFPA) standards that establish minimum requirements for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types used, instrumentation and control, and exhaust systems, among others. The direct-drive fire pump engine, and anything connected to the engine that may affect its performance abilities, must be tested and certified by an independent agency (*e.g.* Underwriters' Laboratories) to be conforming to the requirements of NFPA Standards 20 (Installation of Stationary Pumps for Fire Protection) and/or 25 (Inspection, Testing and Maintenance of Water-Based Fire Protection Systems).[51] Adding exhaust system controls to these engines would void the existing certifications.[52]

<u>STEP THREE: Rank Remaining Control Technologies by Control Effectiveness</u>

Both feasible control technologies, ultra-low sulfur diesel fuel and Tier 2 engine technology, are ranked No. 1. These two technologies are not mutually exclusive and can be used in conjunction with each other to achieve the lowest feasible emissions levels. The Air District has therefore determined that the use of these two technologies for the emergency fire pump engine is the Best Available Control Technology. There are no collateral adverse impacts that would call into question the selection of these technologies as BACT. Because the Air District has chosen the top-ranked control technologies, no further analysis is required under EPA's top-down BACT approach.

<u>Determination of BACT Emissions Limit for Firepump Emissions</u>:

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[49] Diesel engine emissions are currently controlled through improvements to the basic engine, rather than through the use of after-treatment technologies (the exception being diesel oxidation catalysts). *See* Washington State University Extension Energy Program report.

[50] Clarke, letter dated December 11, 2006 to the South Coast Air Quality Management District.

[51] In addition, even if add-on post-combustion technologies were technologically feasible for an emergency fire pump engine, the would not be cost-effective for an engine that is operated only a small number of hours per year. With a small number of operating hours, the cost per hour of operation of adding a post-combustion control system would be astronomical.

[52] March 30, 2005, letter from the California Air Resources Board (CARB) to Clarke Fire Protection Products (recognizing the limited number of options that direct-drive fire pump manufacturers have in replacing or modifying engines); Clarke December 11, 2006, letter to the South Coast Air Quality Management District.

For the fire pump engine, technological and economic limitations make the imposition of a numerical emissions limit infeasible. Determining compliance using an emissions limitation would require direct monitoring of the emissions stream from the engine itself, either using a continuous emissions monitor permanently installed on the engine or through periodic source tests. Both of these alternatives would be prohibitively costly, especially for an engine that will be operated only for a small number of hours each year. In addition, conducting periodic source tests would require the engine to be started up and operated solely for the purpose of testing, which would add significantly to the annual operating hours and associate emissions.

The BACT requirement can more feasibly and economically be enforced by requiring that the facility use an EPA-certified Tier 2 diesel engine. The EPA certification process requires testing by the engine manufacturer to ensure that the engine will meet the established Tier 2 limits. Tier 2 engines have emission rates below 4.27 grams/hp-hr NO_2, 0.33 grams/hp-hr Carbon Monoxide, and 0.12 grams/hp-hr Particulate Matter.[53] By requiring the facility to use an EPA-certified engine, the Air District can ensure that the engine will comply with the BACT requirement and the substantive Tier 2 emissions limits. The proposed Federal PSD Permit authorizes the use of a Clarke JW6H-UF40 engine, which is certified to EPA Tier 2. Use of a different, non-certified engine would not be authorized under the permit. The engine will have to use ultra-low-sulfur diesel fuel because in California that is the only fuel that can be sold for use in such engines.

D. Greenhouse Gases and Best Available Control Technology

The Air District has also examined the potential for greenhouse gas emissions from the proposed facility. The District's conclusions are outlined in this section.

1. Global Climate Change and the Current State of Greenhouse Gas Regulation

As the Bay Area's primary air quality regulatory agency, the Air District is working proactively to address the problem of global climate change. Global climate change poses a significant risk to the San Francisco Bay Area with impacts such as rising sea levels, reduced runoff from snow pack in the Sierra Nevada, increased air pollution, impacts to agriculture, increased energy consumption, and adverse changes to sensitive ecosystems. Global climate change is exacerbated by emissions of so-called greenhouse gases, which include primarily carbon dioxide (CO_2) but also gases such as nitrous oxide (N_2O) and methane (unburned natural gas), among others. The generation of electricity from burning natural gas produces greenhouse gases in addition to the criteria air pollutants addressed above.[54] For this reason, fossil-fuel fired power plant projects implicate global climate change issues and have recently become the subject of heightened scrutiny in this area.

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[53] EPA Air Nonroad Diesel Rule, EPA420-F-04-032, May 2004.

[54] Fossil-fuel fired power plants have the potential to emit a number of greenhouse gases, including CO_2, CH_4 and nitrous oxide (N_2O). CO_2 emissions represent the largest Greenhouse Gas emissions, however, and provide a useful shorthand for referring to emissions of all greenhouse gases combined. Emissions of greenhouse gases in general are therefore often reported in terms of "CO_2 equivalents", which means the amount of CO_2 emissions that would have the same climate impact as a suite of multiple greenhouse gases. The use of "CO_2 equivalents" allows for a meaningful comparison among different emissions made up of varying combinations of different greenhouse gases. The Air District therefore focuses on CO_2 equivalents in this analysis to evaluate greenhouse gas emissions.

The Air District's efforts are closely coordinated with California's initiatives to address global climate change at the state level. The California Global Warming Solutions Act of 2006 (AB32) requires the California Air Resources Board (ARB) to adopt a statewide Greenhouse Gas emissions limit equivalent to the statewide GHG emissions levels in 1990 to be achieved by 2020. To achieve this end, ARB was given a mandate to adopt rules and regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions. The ARB is expected to adopt early action GHG reduction measures in the near future to reduce greenhouse gas emissions by 2020. ARB has adopted regulations requiring mandatory GHG emissions reporting. The facility is expected to report all GHG emissions to meet ARB requirements.

The Electricity Greenhouse Gas Emission Standards Act (SB136812) was also enacted in 2006, requiring that base-load generation resources or contracts be subject to a Greenhouse Gas or Environmental Performance Standard. At its January 25, 2007, meeting, the California Public Utilities Commission (CPUC) adopted an Emissions Performance Standard for the state's Investor Owned Utilities of 1,100 pounds (or 0.5 metric tons) CO_2 per megawatt-hour (MW-hr). The Emissions Performance Standard applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.

The status of Greenhouse Gas regulation is not as well developed under the federal PSD Permit program, however. Federal PSD Permit requirements apply only to "Regulated NSR Pollutants", and "Regulated NSR Pollutants" are defined as (among other things) pollutants that are "subject to regulation" under the Clean Air Act ("CAA"). *See* 40 C.F.R. §§ 52.21(j)(2), (b)(50). Whether Greenhouse Gas emissions are subject to Federal PSD Permit requirements therefore turns on whether they are "subject to regulation" under the Clean Air Act. The United States Supreme Court has recently determined that certain Greenhouse Gases are "Air Pollutants" within the meaning of CAA Section 302(g). *See Massachusetts v. EPA*, 549 U.S. 497, 127 S. Ct. 1438 (2008), meaning that EPA may regulate them under the CAA if appropriate. That ruling did not resolve the issue of whether Greenhouse Gases are "subject to regulation" for purposes of the PSD program. EPA permitting authorities have taken the position that "subject to regulation" means that the agency has actually adopted substantive regulatory requirements for a pollutant, and that EPA has not done so with Greenhouse Gases, and so the PSD Permitting Requirements are not applicable. Others have taken the position that "subject to regulation" means only that EPA would have the authority to regulate the pollutant under the CAA, and that it is clear after the *Massachusetts* decision that EPA does have authority to regulated Greenhouse Gases as "Air Pollutants" under CAA Section 302(g).

This issue of whether Greenhouse Gases are subject to Federal PSD Permit requirements has been raised in several contexts, most notably in appeals of PSD Permits to EPA's Environmental Appeals Board ("EAB"). In the one substantive decision that the EAB has reached to date, the EAB remanded the permit to EPA Region 8 to consider the issue more thoroughly. *See* Order Denying Review In Part and Remanding In Part, *In re Deseret Power Elec. Coop. (Bonanza)*, PSD Appeal No. 07-03, __ E.A.D. __ (EAB Nov. 13, 2008). In that decision, the EAB determined that EPA has the discretion under the CAA to decide whether or not Greenhouse Gases should be subject to the Federal PSD Program, and that the agency has not made any historical or current determination of whether to exercise that discretion one way or another. The EAB therefore remanded the issue to EPA Region 8 with directions that the Region should consider from scratch the issue of whether the

Agency should exercise its discretion to regulate Greenhouse Gases under the PSD Program. The EAB also suggested that it may be more appropriate for the Agency to address the issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. *Id.*, Slip. Op. at p. 63-64. It therefore remains, for the time being, an open question as to whether Greenhouse Gas emissions from the proposed Russell City Energy Center should be subjected to Federal PSD Permit requirements.

For the Russell City Energy Center, the Air District is the PSD Permit issuing authority acting on behalf of EPA pursuant to the Delegation Agreement between the two agencies. In this role, it would normally fall to the Air District to determine how EPA should and will exercise its discretion whether to subject Greenhouse Gas emissions to the Federal PSD Program in the wake of the *Deseret Power* decision. There is very little definitive evidence as to how EPA will decide this issue, however, and it is therefore difficult for the Air District to make such a determination. But for this project such a determination is not necessary, because the applicant has requested that the Air District assume without deciding that Greenhouse Gases are subject to PSD Permit requirements and undertake a PSD Top-Down BACT analysis for the proposed project's Greenhouse Gas emissions. The applicant believes that the Russell City Energy Center as proposed utilizes technology to limit greenhouse gas emissions that meets the definition of Best Available Control Technology as used in the Federal PSD Regulation (40 C.F.R. § 52.21(b)(12)). The applicant has therefore requested that the Air District undertake a Greenhouse Gas BACT analysis and impose an enforceable Greenhouse Gas BACT permit limit, which the applicant will voluntarily accept regardless of whether BACT is required for Greenhouse Gases.

2. Greenhouse Gas BACT Analysis for the Proposed Russell City Energy Center

Because the applicant has voluntarily requested a BACT analysis for greenhouse gases, the Air District conducted a BACT analysis for Greenhouse Gases for the Russell City Energy Center without deciding whether EPA would decide that Greenhouse Gases are subject to the Federal PSD permitting requirements. The Air District's analysis is set forth in this section, following EPA's five-step "top-down" BACT methodology.

In conducting this analysis, the Air District consulted the sources of previous BACT determination such as the federal and California BACT clearinghouses discussed above in connection with the BACT analyses for other pollutants. As BACT has never been applied to greenhouse gases, however, these sources of information did not provide any guidance to inform this analysis. Given the absence of prior BACT determinations, the Air District also reviewed various regulatory limits on greenhouse gas emissions that have been enacted recently. Regulatory limits do not necessarily reflect the most appropriate emissions limit for a specific facility, which must be determined on a case-by-case basis, but they can be helpful in providing some context for making such a determination. The regulatory limits that have been adopted for greenhouse gas emissions reviewed by the Air District are set forth in Table 20.

TABLE 20: Regulatory Limits on Greenhouse Gas Emissions From Combined-Cycle Power Plants	
Jurisdiction	Greenhouse Gas Emissions Limit (CO_2 Equivalent)
Delaware (Distributed generators installed before 1/1/2012)[55]	1,900 lb/MW-hr
Delaware (Distributed generators installed 1/1/2012 or later)[56]	1,650 lb/MW-hr
Massachusetts[57]	1,800 lb/MW-hr
Washington[58]	1,100 lb/MW-hr
California[59]	1,100 lb/MW-hr
Oregon[60]	675 lb/MW-hr (calculated after subtracting offsetting emissions credits)

The Air District's top-down BACT analysis for greenhouse gases is set forth below.

<u>STEP ONE: Identify Control Technologies</u>

Combustion Controls

CO_2 is a product of combustion of fuel containing carbon, and it is inherent in any power generation technology using fossil fuel. There is no way to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place, as with the regulated air pollutants addressed above.

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[55] Delaware Department of Natural Resources and Environmental Control, Regulation No. 1144: Control of Stationary Generator Emissions, § 3.2; 73 Fed. Reg. 23,101, 23,102-103 (Apr. 29, 2008) (codifying approval in the Code of Federal Regulations at 40 C.F.R § 52.420). This SIP approval is currently under review by EPA's Office of Air and Radiation.

[56] *Id.*

[57] 310 Mass. Code Regs. 7.29.

[58] Wash. Rev. Code Ann. § 80.80.040. This limit applies to all baseload electric generation for which electric utilities enter into long-term financial commitments on or after July 1, 2008. "Baseload electric generation" means electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent. *Id.* § 80.80.010.

[59] CPUC, Interim Opinion On Phase 1 Issues: Greenhouse Gas Emissions Performance Standard, Jan. 2007. In 2006 California adopted SB 1368, requiring that the California Public Utilities Commission (CPUC) establish an interim emissions performance standard (EPS) for long-term procurement contracts at a level no be greater than emissions from a combined cycle gas turbine plant. The CPUC undertook a rulemaking procedure and established an EPS for covered facilities of 1,100 pounds of CO_2 per megawatt hour. The California Energy Commission (CEC) approved a similar requirement for municipal utilities. The CPUC ruling found that CCGTs were the most efficient technology for burning of fossil fuels.

[60] Or. Admin. Rules 345-024-0550 (limit expressed as 0.675 lb CO_2/kW-hr). This limit applies base-load gas plants and non-base load plants, and it can be met through the use of offsets. This means that actual CO_2 emissions can be higher than the stated limit, if the facility provides CO_2 emissions credits obtained by reducing CO_2 emissions elsewhere.

The only effective means to reduce the amount of CO_2 generated by fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

The combined-cycle natural gas turbine technology proposed for the Russell City Energy Center is among the most efficient electrical generating technology created to date. Combined-cycle natural gas turbines are a more efficient and cleaner burning source of electricity than any other fossil fuel technology. EPA has found that, compared to the average air emissions from coal-fired generation, natural gas produces half as much CO_2.[61] (Note also that natural gas is far cleaner than other carbon fuels in terms of other air pollutants such as particulate matter, SO_2, mercury, and other heavy metals.) The use of such high-efficiency energy generation technology is a control technology that will limit greenhouse gas emissions from the facility.

Post-Combustion Controls

Beyond using high-efficiency generation technologies to reduce the amount of greenhouse gases created when the power is generated, there are technologies emerging to capture greenhouse gases after they are generated and prevent them from entering the atmosphere where they can contribute to global climate change. These emerging post-combustion capture technologies generally consist of processes that separate CO_2 from flue gas after conventional combustion, and then inject it into geologic formations (such as oil and gas reservoirs, unmineable coal seams, and underground saline formations) or store it in terrestrial repositories. Such technologies might generally be considered as analogous to other technologies that remove or reduce criteria pollutant concentrations pollutants from flue gas streams, *e.g.*, ammonia injection as part of selective catalytic reduction (SCR) for NOx reduction. District staff have identified carbon capture and storage as the only potential post-combustion control technology for CO_2 emissions. If implemented, this technology would further reduce CO_2 emissions beyond the levels achievable by using energy-efficient power generation equipment.

STEP TWO: Eliminate Technically Infeasible Options

Combustion Controls

Energy-efficient power generation is a feasible and proven technology. The energy-efficient natural-gas fired combined-cycle combustion turbine technology proposed for the Russell City Energy Center is such a technology.

Post Combustion Controls

In contrast to readily-available high-efficiency generation technologies, emerging carbon capture and sequestration technologies are in their infancy and are not currently feasible for projects such as the proposed Russell City Energy Center. There are currently no carbon capture and sequestration

[61] *See* EPA, *Natural Gas*, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

systems commercially available for full-scale power plants in the United States. The U.S. Department of Energy (DOE) has indicated that its goal is to develop carbon capture and sequestration at a research and development scale by 2012 and that it expects integrated systems be available for full commercial deployment in the 2025 timeframe. (*See* 73 Fed. Reg. at 44,370.) A survey conducted at the 2007 Electric Power Research Institute (EPRI) summer seminar found that only five percent of the participants (industry professionals) indicated they thought CO_2 capture would be commercially available by 2015, only 24 percent thought it would be available by 2020, and only 15 percent by 2025.[62] EPA itself has recognized that add-on controls may not be adequately demonstrated for CO_2. (*See* 73 Fed. Reg. at 44,508.)

In addition, even if carbon capture and sequestration were fully matured, the feasibility of such controls for a particular power plant would depend on the availability of appropriate sequestration sites (sinks) in the vicinity of the plant.[63] While basins within Alameda County are under investigation for the potential for carbon sequestration, there are no such sites that have been demonstrated as appropriate for sequestration at this time.

Finally, carbon capture and sequestration may also have ancillary environmental and societal impacts that need further evaluation before the technology can be considered feasible. For example, there may be the potential for effects on sensitive species and other wildlife, and cultural and environmental justice issues. Land use and water and mineral resources will also be important considerations. Sequestration of carbon in the ground also runs the risk of leakage into the air, and the science and technology of remediating leakage is still emerging.[64] These issues highlight the further development that is needed before this technology can be considered a feasible option for controlling greenhouse gas emissions.

For the foregoing reasons, the Air District eliminated carbon capture and sequestration from consideration as an available control technology for purposes of its BACT analysis. The Air District will continue to monitor the development of carbon capture sequestration as a potential control technology for the future, however.

STEP THREE: Rank Remaining Control Technologies by Control Effectiveness

Based on the first two steps of the top-down BACT analysis, there is only one available and feasible control technology to reduce greenhouse gas emissions from the project, the use of high-efficiency power generation technology. This technology is therefore ranked No. 1 in the BACT analysis, and is the technology that the Air District would choose if BACT were required for a Federal PSD Permit.

[62] Washington Department of Ecology, Preliminary Cost Benefit and Least Burden Analyses, Document 08-02-007, at 10 (Feb. 2008).
[63] Burton, *et al.*, Geologic Carbon Sequestration Strategies for California, CEC Systems Office Report to the Legislature, at 20.
[64] *Id.*, at 85.

There are no collateral adverse impacts that would call into question the selection of high-efficiency power generation technology as BACT.[65] Because the Air District has chosen the top-ranked control technology, no further analysis is required under EPA's top-down BACT approach.

Determination of BACT Emissions Limit for Greenhouse Gases

Having chosen high-efficiency power generation technology as the Best Available Control Technology, the next step in applying the BACT requirement is to adopt a numeric limitation for greenhouse gas emissions. Again, EPA has not determined whether it should exercise its discretion to regulate greenhouse gases under the Federal PSD program, but the District has calculated what an appropriate BACT emission limitation would be for greenhouse gases if they were subject to the BACT requirement at the voluntary request of Calpine.

According to data compiled by the California Energy Commission, natural-gas burning combined-cycle combustion turbine technology can achieve an efficiency of around 56%.[66] The Westinghouse 501F turbines proposed for the Russell City Energy Center are rated at 55.8% efficiency, squarely within the range of the best-performing combined-cycle turbines.[67] Based on this level of performance, the Energy Commission has concluded that the project's equipment will "represent the most efficient combination to satisfy the project objectives." (Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-6.)

To determine an appropriate CO_2 emissions limitation achievable for this level of energy-efficient technology, the Air District used emissions performance data from other similar facilities. Information from the Energy Commission from the years 2004 and 2005, which showed emissions from baseload combined-cycle gas turbine power plants ranging from 794 lbs to 1058 lbs per MW-hr of electricity generated. The Air District also reviewed data from two similar Calpine power plants, the Delta Energy Center and the Metcalf Energy Center, which reported 2006 emissions of 855 and 912 lb/MWhr, respectively, when calculated in accordance with the methodology provided by the CEC for purposes of demonstrating compliance with the EPS.

This data is highly informative as to the general level of CO_2 emissions performance that can be expected from these turbines during their operational lives. The data must be viewed conservatively in determining what emissions limits would be appropriate as mandatory BACT compliance limits, however, given that the data represents a snapshot of turbine performance and not a continued

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[65] California Energy Commission Decision for the Russell City Energy Center AFC, Alameda County (Sept. 11, 2002), at p. 67.

[66] This determination was made based on a comparison of three individual models of combined-cycle combustion turbines using data from Gas Turbine World, an independent technical magazine that covers the gas turbine industry. *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. The turbines evaluated had nominal energy efficiencies of between 55.8% and 56.5%. During review of the September 2007 amendment to that decision, CEC staff "testified that the proposed changes would not change any of the findings or conclusions in the 2002 Decision." Presiding Member's Proposed Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Alameda County, August 23, 2007 (CEC-800-2007-003-PMPD), at 57.

[67] *See* Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4.

demonstration of compliance with an enforceable CO_2 emission limitation throughout the turbines' total operational lifetime. As there have historically been no enforceable emissions limitations on CO_2 emissions, such comprehensive data is not available at this time. For these reasons, caution must be exercised in determining what emissions level would be appropriate as an enforceable upper limit on emissions exceedances of which would be subject to legal enforcement action. Such an approach to establishing enforceable limits has been endorsed by EPA, which has made clear that BACT limits should not necessarily reflect the maximum possible emissions control efficiency that can be achieved under the most favorable conditions, but rather at levels that will allow facilities to achieve compliance consistently over time under all operating conditions. *See In re Prairie State Generating Co.*, PSD Appeal No. 05-05, 13 E.A.D. __, slip. op. at 72 (EAB Aug. 24, 2006), *aff'd*, *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007), *reh'g denied and reh'g en banc denied,* 2007 U.S. App. LEXIS 24419 (7th Cir., Oct. 11, 2007); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000).

The Air District has therefore concluded that, without a demonstrated track record of compliance with enforceable permit limits and the need to ensure that the facility would be able to comply with an emissions limit under all foreseeable operating conditions, a reasonable compliance margin would be necessary in adopting any enforceable BACT limit for CO_2 emissions. Based on the available data the Air District has reviewed for similar turbines, and incorporating a reasonable compliance margin, the Air District concludes that if BACT is required for CO_2 emissions, an enforceable limit of 1100 lb/MW-hr would best represent the BACT requirement in the PSD regulation. The Air District notes that this emissions limitation would be consistent with the most stringent emissions standard in any regulatory requirement adopted to date, as discussed in the beginning of this analysis.[68] This limitation also compares favorably with the average emissions rate for all natural gas fired power plants, which EPA found to 1135 lbs/MW-hr.[69]

To comply with a CO_2 emissions limit of 1100 lb/MW, the facility would be required to limit its CO_2 emissions to 684,200 lb/hr, given its maximum power output of 622 MW. CO_2 emissions are proportional to the amount of fuel burned, and so the Air District is proposing to ensure compliance with this standard through an enforceable fuel throughput limit, expressed in terms of the heat input of the fuel burned (Higher Heating Value (HHV)).[70] CO_2 emissions correlate to heat input at 116.19 pounds of CO_2 emitted per million British thermal units (MMBtu) of heat input. A 684,200 lb/hr CO_2 emissions rate therefore corresponds to 5,888.6 MMBtu of heat input for both turbine/HRSG trains combined, or 2,944.3 MMBtu for a single turbine/HRSG train. Proposed condition No. 13 limits the heat input to 2,238.6 MMBtu per turbine/HRSG train, and will ensure that CO_2 emissions do not exceed the BACT emissions limit outlined above. Corresponding heat input limits in proposed conditions Nos. 14 and 15 will ensure compliance on a daily and annual basis as well. To the extent that EPA may exercise its discretion and require PSD permits to ensure that facilities will use BACT to control greenhouse gas emissions, the proposed Russell City Energy Center will comply with BACT based on these enforceable permit conditions.

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68 *See* Table 20 above. Note that Oregon's limit may be complied with using offsets, meaning that plants subject to the limit are not themselves required to meet the emissions limit. As BACT limits must be complied with regardless of offsets, Oregon's limit is not directly comparable in a BACT analysis.
69 EPA, *Natural Gas*, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.
70 *See* Appendix A for the correlation between natural gas combusted and the amount of CO_2 generated.

VI. PSD AIR QUALITY IMPACT ANALYSIS

The Federal PSD regulations and corresponding Air District regulations require that the District undertake an air quality impact analysis for each facility subject to PSD permit requirements. The Air District has done so for the proposed Russell City Energy Center. The results of this analysis are presented in the *Summary of Air Quality Impact Analysis for the Russell City Energy Center*, set forth in Appendix C. The analysis used sophisticated EPA-approved air pollution models to evaluate the ambient air impacts from air pollutant emissions from the proposed facility. The analysis found that the emissions from the proposed facility would not cause or contribute to air pollution in violation of any applicable National Ambient Air Quality Standard or applicable PSD increment. The analysis also examined the potential for impacts to visibility, soils and vegetation resulting from air emissions from the proposed facility and found no significant impacts. The analysis also examined the potential for associated growth from the facility and found that there would be no significant associated growth. The analysis also examined the potential for impacts to "Class I" areas, which are areas of special natural, scenic, recreational, or historic value (such as National Parks). The analysis found that there would be no significant impact to Class I areas. Full details are set forth in Appendix C Based on this analysis, the proposed facility complies with the air quality impacts analysis requirements in 40 C.F.R. sections 52.21(k) through (p).

VII. OTHER APPLICABLE LEGAL REQUIREMENTS

Beyond the Federal PSD Regulations, there are a number of important non-PSD air quality-related requirements applicable to the proposed Russell City Energy Center. The Air District reviewed these additional applicable requirements in its Final Determination of Compliance for the project, prepared in conjunction with the California Energy Commissioning licensing proceeding. The Air District conducted this review in the Final Determination of Compliance hand-in-hand and in the same document as its initial review and Statement of Basis for the Federal PSD Permit, although as explained above these two permits are separate legal entities governed by different legal authorities. The District incorporates that Final Determination of Compliance herein for purposes of public information, although as noted above the state-law permitting process is not being reopened at this time. The Final Determination of Compliance is attached hereto as Appendix D, and provides a detailed review of the applicable non-PSD permitting requirements.

In the context of a Federal PSD Permit review, it is important to note that the District's review found that the facility would comply with the applicable Federal New Source Performance Standards in Part 60 of Title 40 of the Code of Federal Regulations. The applicable subparts of 40 C.F.R. Part 60 include Subpart A, "General Provisions", Subpart KKKK "Standards of Performance for Stationary Combustion Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery boilers ("HRSGs") will comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized in Table 21 below:

Table 21 – Applicable New Source Performance Standards in 40 C.F.R. Part 60

Source	Section	Requirement	Compliance Verification
Gas Turbines and HRSGs	Subpart KKKK		
	40 CFR § 60.4330(a)(2)	0.060 lb SO_2/MM BTU	Sources limited by permit condition to 0.0028 lb SO_2/MM BTU maximum
	40 CFR § 60.4320 (a)	15 ppm NO_x (15% O_2)	Sources limited to 2 ppm NO_x (15% O_2)
Fire pump Diesel Engine	Subpart IIII		
	40 CFR § 60.4200 *et seq.*	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* Diesel Firepump Engine BACT Analysis.

Interested persons should also take note of the health risk screening assessment that the Air District completed under its Risk Management Policy, referenced in Section IV.B above. Under the 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. As discussed in Section IV.B, the increased carcinogenic risk attributed to this project is less than 1.0 in one million, and the chronic hazard index and acute hazard index attributed to the emission of non-carcinogenic air contaminants are each less than 1.0. These risk levels are less than significant for project permitting purposes. The Air District reiterates these results here because they have informed the Air District's conclusions that the control technologies chosen to comply with the Federal PSD Permit requirements will not have any significant adverse ancillary environmental impacts. Please see Appendix B for further information on the Health Risk Assessment.

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

The emissions from the proposed project will not cause or contribute to any significant public health impacts in the community. As described in detail above, the Air District has undertaken a detailed review of the potential public health impacts of the emissions authorized under the proposed permitting action, and has found that they will involve no significant public health risks. The risk levels involved (lifetime cancer risk of 0.7 in one million; maximum chronic Hazard Index of 0.007; and maximum acute Hazard Index of 0.024) are below what the Air District, EPA, or any other public health agency considers to be significant. The Air District has concluded that there are no significant impacts due to air emissions related to the Russell City Energy Center after all of the mitigations required by Federal and District Regulations and the California Energy Commission are implemented. There is no adverse impact on any community due to air emissions from the Russell City Energy Center and therefore there is no disparate adverse impact on an Environmental Justice community located near the facility.

VIII. PROPOSED PERMIT CONDITIONS

The Air District is proposing the following permit conditions to ensure that the proposed project will comply with all applicable Federal PSD requirements. Compliance with emissions limits will be verified by continuous emission monitors and/or periodic source tests. The proposed facility will be required to maintain records of emissions and report them to the Air District for compliance purposes.

The Air District developed the following list of proposed permit conditions as part of its integrated permit review process covering both Federal PSD and state law requirements. As such, the entire list contains some conditions required by the Federal PSD Regulation and some conditions required under state law. In some instances a permit condition may be required under both the Federal PSD Regulation and state law, for example with certain Best Available Control Technology requirements where federal and state law overlap. The requirements of the Federal PSD Regulation are those discussed in the previous sections of this document, and the proposed conditions that are being implemented pursuant to the Federal PSD Regulation are the conditions necessary to ensure compliance with the requirements discussed above. To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in "strike-through" format below. For a full understanding of what permit conditions are required by the Federal PSD Regulation, the reader should consult the detailed analysis of Federal PSD requirements set forth above, the Federal PSD Regulation itself, relevant decisions of the Environmental Appeals Board, and other related authorities. Permit conditions that are not being proposed pursuant the Federal PSD Regulation are not part of this proposed permitting action; persons interested in any such conditions will need to take up their concerns in the appropriate state law forum (to the extent one is available at this stage).[71]

The Air District is also providing citations to relevant authorities following certain conditions to help the reader understand the legal authority under which the Air District is proposing the condition. These citations are intended as reader aids only, and should not be considered the Air District's definitive analysis of the legal authorities underlying each condition. In particular, many conditions may be authorized by or otherwise implicate multiple legal authorities, some of which may not be listed for each condition. For a complete discussion of what permit requirements are being imposed pursuant to the Federal PSD Regulation, the reader should refer to the relevant discussions in previous sections of this document.

Russell City Energy Center
Proposed 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

[71] As noted above, the state-law permitting process has been completed and is now final. Avenues for reviewing state-law conditions have therefore been exhausted.

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 performed, 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 9.0 pounds per hour or 0.0040 lb PM_{10}/MM BTU of natural gas fired. (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) 500 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. Permit Conditions for Cooling Towers

44. 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)

45. 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 44. 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)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. 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)

47. 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))

48. 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)

49. 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)

IX. PROPOSED PERMIT DECISION

The Air District's Air Pollution Control Officer ("APCO") has concluded that the proposed Russell City Energy Center power plant, which is composed of the permitted sources listed below, will comply with all applicable Federal PSD Permit requirements. The APCO is therefore proposing to issue a Federal PSD Permit for the Russell City Energy Center as set forth in this document. The following sources will be subject to the proposed permit conditions 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, 300 hp, 2.02 MMBtu/hr rated heat input.

Pursuant to the requirements of 40 C.F.R. Part 124, the Air District's proposal to issue a Federal PSD Permit for this project is subject to public notice and an opportunity for interested members of the public to review and comment on it. Information on how the public can participate in and comment on this proposed decision is provided in Section II.D. above, and will be provided to the public by formal legal notice.

Appendix A

Greenhouse Gas (CO_2) Calculations

The following operating parameters were utilized to calculate CO_2 emissions formed from the combustion of natural gas.

ISO operating conditions, 59F[72]
Heat Input (HHV) Gas Turbine: 1,968 MMBtu/hr
Heat Input (HHV) Duct Burner: 200 MMBtu/hr
Total Heat Input each Power Block: 2,168 MMBtu/hr
Power Output: 311 MW each block/ 622 MW both blocks

Heat input rate limits for the gas turbines and HRSG are given below in **Table A-1**.

Table A-1
Maximum Allowable Heat Input Rates

Source	MM Btu/hour-source
S-1 and S-3 Gas Turbines, each	2,038.6
S-1 CTG and S-2 HRSG, each power block S-3 CTG and S-4 HRSG, each power block	2238.6[a]

[a] maximum combined firing rate for each power block consisting of gas turbine and HRSG duct burner (200 MM Btu/hr)

CO_2 Emissions Calculations

For each power block:
Natural gas fuel throughput = (2,168 MMBtu/hr)/(1050 Btu/scf) = 2,064,762 scf/hr
CO_2 emissions factor[73] = 122 lb CO_2/1000 scf
CO_2 emissions = (2,064,762 scf/hr)*(122 lb CO_2/1000 scf) = 251,900 lb/hr
CO_2 emissions correlation = (251,900 lb/hr)/(2,168 MMBtu/hr) = **116.19 lb/MMBtu**

Calculate the maximum hourly emissions rate (two power blocks):
Maximum CO_2 emission rate = 1,100 lb/MW-hr
Maximum hourly CO_2 emissions = (1,100 lb/MW-hr)*622 MW **= 684,200 lbs/hr**

Calculate the maximum heat input (one power block):
Maximum Heat Input = (342,100 lbs/hr)(116.19 lb/MMBtu) = **2944.3 MMBtu/hr**

[72] From Permit Application for the Russell City Energy Center, prepared by Atmospheric Dynamics, Inc. and Tetra Tech EC, Inc., November 2006.

[73] From BAAQMD Data Bank.

Appendix B

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 6, “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 B-1**.

Table B-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 B-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

Appendix C

Summary of Air Quality Impact Analysis for the Russell City Energy Center

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

December 8, 2008

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}[74], 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 40 C.F.R. Section 52.21(k)-(o) and related authorities. The Air District has also adopted regulations on performing air quality impact analysis in its New Source Review (NSR) Rule: Regulation 2, Rule 2. These regulations provide additional guidance on performing air quality impact analyses, but do not override the EPA regulations. In the case of any inconsistency between Air District Rule 2, Regulation 2 and 40 C.F.R. Section 52.21, the federal regulations are controlling.

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 I

Comparison of proposed project's annual worst-case emissions
to significant emission rates for air quality impact analysis (tons/year)

Pollutant	Proposed Project's Emissions	PSD "Major Source" Threshold Emission Rate	EPA PSD Significant Emission Rate
NO_2	134.6	100	40
CO	584.2	100	100
PM_{10}	86.8	100	15
SO_2	12.2	100	40

[74] 40 C.F.R Section 52.21(i)(1)(xi) and BAAQMD regulations require the District to use PM_{10} as a surrogate for $PM_{2.5}$ in Air Quality Impact Analyses.

Table I indicates that the proposed project emissions exceed the PSD "major source" threshold levels for nitrogen oxides (NO_2) and carbon monoxide (CO). 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 40 C.F.R. Section 52.21, District Regulation 2, Rule 2, and EPA guidance documents.

The PSD Regulations also contain 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 40 C.F.R. Section 52.21(o) and 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 EPA's NSR Workshop Manual and Section 414 of Regulation 2 Rule 2. According to subsection 414.1 and the NSR Workshop Manual, 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 and the NSR Workshop Manual, 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 an analysis of any PSD source that may impact 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 startup, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average.[75] Startup conditions were modeled with both turbines in startup mode.

[75] Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Commissioning emissions are temporary emissions that are not subject to the Air Quality Impact Analysis requirement. EPA only requires an analysis of commissioning activity impacts if it is shown that the emissions impact a Class I area or an area where a PSD increment is known to be violated. 40 C.F.R. Section 52.21(i)(3).

TABLE II

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

Pollutant Source	Max. (1-hour)	Max. (8-hour)	Max. (24-hour)	Max. Annual Average	Start-up[a] (1-hour)	Start-up[a] (8-hour)
NO_x						
Turbine/Duct Burner 1	—	—	—	1.94	—	—
Turbine/Duct Burner 2	—	—	—	1.94	—	—
Fire Pump	—	—	—	0.00211	—	—
Each Cooling Tower Cell (9 total)	—	—	—	—	—	—
CO						
Turbine/Duct Burner 1	2.48	1.34	—	—	169.95	80.24
Turbine/Duct Burner 2	2.48	1.34	—	—	169.95	80.24
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] Start-up is the bringing of a turbine from idle status up to power production.

The EPA guideline models AERMOD (version 07026) and SCREEN3 (version 96043) were used in the air quality impacts analysis. Because an Auer land use analysis showed that the area within 3 km is classified as rural, the AERMOD option of increased surface heating due to the urban heat island was not selected.

Meteorological data was available from the Automated Surface Observing System (ASOS) at the Oakland International Airport for the years 2003-2007. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. Based upon this comparison the Oakland ASOS data was considered representative of the RCEC project location and met all EPA data completeness requirements.

Upper air data for the same time period was available from the closest representative NWS radiosonde station, also the Oakland International Airport.

Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated using the Building Profile Input Program for PRIME [BPIPPRM (version 04274)]. 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.

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.

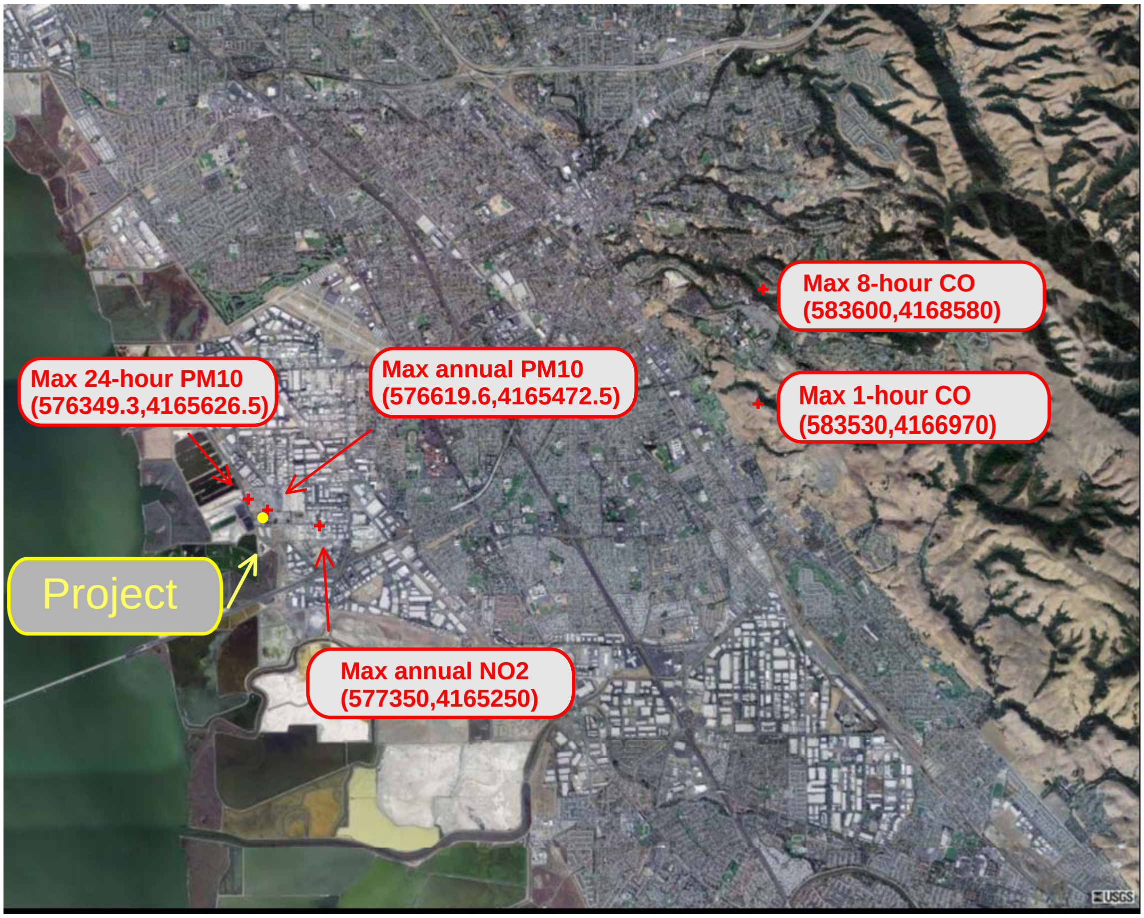
TABLE III

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

Pollutant	Averaging Time	Start-up	Inversion Break-up Fumigation Impact	Shoreline Fumigation Impact	Normal operation	Significant Air Quality Impact Level
NO_2	annual	—	—	—	**0.16**	1
CO	1-hour	**1574**	6.5	36.5	41	2000
	8-hour	**321**	—	—	5.9	500
PM_{10}	24-hour	—	2.9	3.2	**4.1**[a]	5
	annual	—	—	—	**0.72**	1

[a]Highest sixth-high 24-hour average concentration (40 C.F.R. Part 51 Appendix W Section 7.2.1.1.b)

Also shown in Table III are the corresponding significant ambient impact levels listed in the NSR Workshop Manual and Section 233 of the District's NSR Rule. In accordance with the NSR Workshop Manual and 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 there will be no impacts above the significant impact levels. No further Source Impact Analysis is required.



FI

GURE 1. Location of project maximum impacts.

CLASS I AREA IMPACT ANALYSIS

In accordance with the NSR Workshop Manual, an impact analysis must be performed for any PSD source within 100 km of a Class I area which increases air pollutant concentrations by 1 μg/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 IV are the results from an impact analysis using AERMOD. 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 μg/m^3 significance level (see Table IV).

TABLE IV

Class I 24-hour air quality impacts analysis for the Point Reyes National Seashore (µg/m^3)

Pollutant	AERMOD	Significance level	Significant
NO_2	0.06[a]	1.0	no
PM_{10}	0.06	1.0	no

[a] Assumed 100% conversion of NO_x to NO_2

ADDITIONAL IMPACTS ANALYSIS

The EPA NSR Workshop Manual states that all PSD analysis must include an additional impacts analysis. The additional impacts analysis assesses the impacts on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source and associated growth.

Visibility Impairment 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.

Soils and Vegetation Analysis

A detailed soil inventory found in the project and impact area was prepared (Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006.) The plant will be located on a site consisting of artificially drained soils formed from alluvium. This land is naturally high in salts, and is not designated by the California Department of Conservation as Prime Farmland or Farmland of Statewide Importance. The project is located entirely within Reyes clay drained soil type series. These soils tend to be very deep, exhibit level to nearly level topography, and are poorly to very poorly drained clays formed in tidal flats. Other soils within 2 miles of the project include Danville silty clay, Sycamore silty loam, Willows clay, Clear Lake clay and Botella silty clay. Some project area soils (Clear Lake, Danville, and Willows) are considered prime farmland soils when found in open field or agricultural areas, but none of the project facilities cross these soils in any other context than land that is zoned and used as urban, industrial land.

A detailed vegetation inventory in the project and impact area is also presented in the Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006. Coastal habitats along the eastern shore of San Francisco Bay include salt marshes, brackish sloughs, coastal prairies, and coastal sage scrub communities. Biological resources located in the hills east of Hayward and San Leandro include Lake Chabot and Anthony Chabot Regional Park, and Garin Regional Park. Ecosystems occurring in these areas include those commonly encountered in the foothills of the Coast Ranges, such as oak woodland and valley/foothill grassland. Biological habitats within the project area consist primarily of coastal salt marsh, brackish/freshwater marsh, salt production facilities (evaporation ponds), ruderal areas, and urban landscapes with horticultural trees and shrubs. The dominant vegetation types are annual grassland and seasonal wetland dominated by saltgrass (Distichlis spicata), and alkalai heath (Frankenia salina). The only sensitive plant community found within the project area is the northern coastal salt marsh habitat. Representative species found in the salt marsh community include pickleweed (Salicornia virginica), salt grass (Distichlis spicata), and alkali heath (Frankenia salina). There are 1.68 acres of seasonal wetlands on the 14.7-acre project site. Much of the historic salt marsh community within 1 mile of the site has been altered or eliminated by urban development, sewage treatment facilities, salt evaporation ponds, and the construction of dikes and levees to prevent flooding and intrusion of saltwater. Remaining salt marsh in the project impact area includes Cogswell Marsh, managed by the East Bay Regional Park District, the Hayward Area Recreation District (HARD) marsh restoration project, and several brackish/freshwater marshes. There are no economically important terrestrial wildlife species within the impact area of the proposed project. Special environmental areas within a 1-mile radius of the project site include Cogswell Marsh, managed by the East Bay Regional Park District, the HARD marsh restoration project and Shoreline Interpretive Center, and a small section of Mt. Eden Creek.

A botanical survey was taken of the area. Table V lists the plant species observed during this survey.

TABLE V

Plant species observed during botanical surveys for the RCEC project

Family	Genus	Species/ subspecies/ variety	Common name
DICOTS			
Apiaceae	*Foeniculum*	*vulgare*	Fennel
Asteraceae	*Conyza*	*canadensis*	Horseweed
	Baccharis	*pilularis*	Coyote brush
	Cotula	*coronopifolia*	Brassbuttons
	Grindelia	*Stricta* var. *angustifolia*	Gumweed
	Sonchus	*oleraceus*	Common sow thistle
Brassicaceae	*Brassica*	*nigra*	Black mustard
Chenopodiaceae	*Chenopodium*	*album*	Lamb's quarters
	Salicornia	*virginica*	Pickleweed
Fabaceae	*Lathyrus*	*Sp.*	Wild pea
Frankeniaceae	*Frankenia*	*salina*	Alkali heath
Geraniaceae	*Geranium*	*molle*	Wild geranium
	Erodium	*cicutarium*	Filaree
Malvaceae	*Malva*	*nicaeensis*	Bull mallow
Myrtaceae	*Eucalyptus*	*globulus*	Blue gum
Papaveraceae	*Eschscholzia*	*californica*	California poppy
Plantaginaceae	*Plantago*	*lanceolata*	English plantain
Polygonaceae	*Rumex*	*crispus*	Curly dock
Primulaceae	*Anagallis*	*arvensis*	Scarlet pimpernell
Solanaceae	*Nicotiana*	*glauca*	Tree tobacco
Urticaceae	*Urtica*	*urens*	Dwarf nettle
MONOCOTS			
Poaceae	*Avena*	*fatua*	Wild oat
	Bromus	*diandrus*	Ripgut grass
	Cortadaria	*Sp.*	Pampas grass
	Cynodon	*dactylon*	Bermuda grass
	Distichlis	*spicata*	Saltgrass
	Elymus	*sp.*	Wild-rye
	Hordeum	*murinum* ssp. *leporium*	--
	Lolium	*multiflorum*	Italian ryegrass
	Vulpia	*microstachys*	Three-week fescue
Juncaceae	*Scirpus*	*sp.*	Rush

The project maximum one-hour average NO_2, including background, is 260 $\mu g/m^3$. This concentration is below the California one-hour average NO_2 standard of 338 $\mu g/m^3$. Nitrogen dioxide is potentially phytotoxic, but generally at exposures considerably higher than those resulting from most industrial emissions. Exposures for several weeks at concentrations of 280 to 490 $\mu g/m^3$can cause decreases in dry weight and leaf area, but 1-hour exposures of at least 18,000 $\mu g/m^3$ are required to cause leaf damage. The maximum annual RCEC NO_2 impact is 0.16 $\mu g/m^3$. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 $\mu g/m^3$. The total annual NO_2 concentration (project plus background) of 28.4 $\mu g/m^3$ is far below these threshold limits (219.0 $\mu g/m^3$). In addition, the total predicted maximum 1-hour NO_2 concentrations of 260 $\mu g/m^3$ would be significantly less than the 1-hour threshold (7,500 $\mu g/m^3$ or 3,989 ppm) for 5 percent foliar injury to sensitive vegetation (USEPA 1991, "Air Quality criteria for oxides of nitrogen").

Plants metabolize and produce carbon monoxide (CO). Soil microorganisms probably act as a buffering system and sink for CO. There are no known detrimental effects on plants due to CO concentrations of 10,000 to 230,000 $\mu g/m^3$, much higher than the RCEC 1 -hour impact of 1574 $\mu g/m^3$ (USEPA 1979, "Air Quality criteria for carbon monoxide").

A variety of plant species were exposed to CO at concentrations of 115,000 $\mu g/m^3$ to 11,500,000 $\mu g/m^3$ from 4 to 23 days (Zimmerman et al.1989, "Polymorphic regions in plant genomes detected by an M13 probe", *Genome* 32: 824-828). While practically no growth retardation was noted in plants exposed at the lower level, retarded stem elongation and leaf deformation were observed at the higher concentrations. Pea and bean seedlings also exhibited abnormal leaf formation after exposure to CO at 27,000 $\mu g/m^3$ for several days (USEPA 1979, "Air Quality criteria for carbon monoxide"). Comparatively low levels of CO in the soil have been shown to inhibit nitrogen fixation. Concentrations of 113,000 $\mu g/m^3$ have been shown to reduce nitrogen fixation, while 572,000 to 1,142,000 $\mu g/m^3$ result in nearly complete inhibition (USEPA 1979, "Air Quality criteria for carbon monoxide"). The maximum 1-hour and 8-hour CO impacts from the RCEC project and are significantly lower: the 1-hour CO concentration is 1574 $\mu g/m^3$ and the 8-hour CO concentration is 321 $\mu g/m^3$.

The deposition of airborne particulates (PM_{10}) can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Deposition rates of 365 g/m^2/year have been shown to cause damage to fir trees, but rates of 274 g/m^2/year and 400-600 g/m^2/year did not damage vegetation at other sites (Lerman, S.L. and E.F. Darley. 1975. Particulates, pp. 141-158. In: Responses of plants to air pollution, edited by J.B. Mudd and T.T. Kozlowski. Academic Press. New York.) The maximum annual predicted concentration for PM_{10} from the RCEC is 0.72 $\mu g/m^3$. Assuming a deposition velocity of 2 cm/sec (worst-case deposition velocity, as recommended by the California Air Resources Board [CARB]), this concentration converts to an annual deposition rate of 0.45 g/m^2/year, which is several orders of magnitude below that which is expected to result in injury to vegetation (i.e., 365 g/m^2/year). The addition of the maximum predicted annual particulate deposition rate for the RCEC to three-year maximum background concentration of 19.6 $\mu g/m^3$, measured at the nearest monitoring station (Fremont) yields a total estimated particulate deposition rate of 12.8 g/m^2/year, utilizing the same 2 cm/sec deposition velocity. This total is still approximately one order of magnitude less than levels expected to result in plant injury.

EPA has established a screening procedure for determining impacts to plants, soils and animals (EPA 450/2-81-078, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," December 1980). Table 3.1 of this EPA guidance document lists screening concentrations for various pollutants, representing minimum concentrations at which adverse growth effects or tissue injuries were reported in the scientific literature. Shown in Table VI below is a comparison of the screening concentrations from the EPA document and the impacts from RCEC.

TABLE VI

Screening Assessment of RCEC impacts on soils and vegetation

Pollutant	Screening concentration[a] (μg/m^3)	Averaging period	Max. modeled impact (μg/m^3)	3-yr max. Fremont background concentration (μg/m^3)	Maximum concentration (impact plus background) (μg/m^3)	Averaging period for comparison
NO_2	3,760	4-hour	130	130	260	1-hour
	3,760	8-hour	130	130	260	1-hour
	564	1 month	130	130	260	1-hour
	94	1 year	0.16	28.2	28.4	annual
CO	1,800,000	Week	321	2245	2,873	8-hour

[a]EPA 450/2-81-078, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," December 1980.

Maximum project NO_2, CO and PM_{10} concentrations would be less than the threshold levels at which scientific studies have shown a potential for negative impacts on soils and vegetation. The proposed project is not expected to have any adverse soils and vegetative impacts.

Growth Analysis

The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region.

There will be little or no associated industrial, commercial, or residential growth as a result of this project. The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth.

The Russell City Energy Center will have approximately 25 full-time employees (Russell City Energy Center AFC Amendment No. 1 (01-AFC-7), November 2006.) The plant is expected to begin commercial operation in the summer of 2012. The entire permanent workforce is expected to commute from within Alameda County. This is a small fraction of the total population of Oakland/Hayward/San Leandro area, which was slightly over 619,000 as of December 2008 (http://www.city-data.com/city). Facility employees are expected to come from the local workforce, regional workforce, or existing staff. There will be no significant impact on local employment. The CEC analysis of socioeconomic impacts of the Final Staff Assessment of 2007 found that "Russell

Energy Center expects that hiring construction and operation workers will occur within the East Bay/Oakland/Hayward region, and as stated above, staff agrees with this determination." Therefore, no significant growth is expected to occur as result of the project.

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 40 C.F.R. Section 52.21, Section 414 of the District's NSR Rule, and related guidance.

Appendix D

Amended Final Determination of Compliance, Russell City Energy Center, BAAQMD June 19, 2007

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 $\geq$ 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 $\leq$ 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 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 annual	119.2 —	77 —	9.5 —	62.4 —	**226.8** **0.14**	19 1.0
CO	1-hour 8-hour	**1977** **348**	1069 178	6.5 —	36.5 —	134.7 5.7	2000 500
PM_{10}	24-hour annual	— —	— —	2.9 —	**3.2** —	2.94 **0.15**	5 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	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

Turbines and HRSGs	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-NOx combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-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 NOx 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, PM10, 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).

NOx (as NO2)	4,805 pounds per calendar day	400 pounds per hour
CO	20,000 pounds per calendar day	5,000 pounds per hour
POC (as CH4)	495 pounds per calendar day	
PM10	432 pounds per calendar day	
SO2	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 NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods 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 SO2 and PM10)
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 NOx)
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 PM10)
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 NOx)
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 NOx, 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 NOx, 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)

(e) 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)
(f) 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)
(i) 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)
(j) 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)
(k) 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)
(l) Particulate matter (PM_{10}) mass emissions at P-1 & P-2 each shall not exceed 6 pounds per hour or 0.0029 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 9 pounds per hour or 0.0038 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 NOx (as NO2) per year (Offsets, PSD)
    (b) 389.3 tons of CO per year (Cumulative Increase, PSD)
    (c) 28.5 tons of POC (as CH4) per year (Offsets)
    (d) 86.8 tons of PM10 per year (Cumulative Increase, PSD)
    (e) 12.2 tons of SO2 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.
    (d) 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)
16. 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. Permit Conditions for Cooling Towers

43. 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)

44. 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 PM10 emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. 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)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

45. 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)

46. 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))

47. 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)

48. 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.

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

Pollutant	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
	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})	0.0029	6	0.0038	9
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 0.00377 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:
(0.00402 lb/MMBtu)/(2238.6 MM Btu/hr) = **9 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: 9 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 ^{o}R]/[180 + 460 ^{o}R])(1 – 0.087) = 692,232 dscfm

Converting to grains/dscf:
(9 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(692,232 dscfm) = 0.00152 gr/dscf

Converting to 6% O_2 basis:
(0.00152 gr/dscf)[(20.95 - 6)/(20.95 – 11.8)] = 0.0025 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:
(6 lb PM_{10}/hr)/(2038.6 MM Btu/hr) = **0.0029 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
PM_{10}[d]	10.6	63.6	10.6	31.8	10.6	31.8

Table B-2 Gas Turbine Start-Up Emission Rates (lb/start-up)						
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 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 = $0.7 \times 10^6/(67{,}554{,}000 \times 0.000005)$ = 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	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)**	**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.

Appendix E

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	Averagin g 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 annual	119.2 —	77 —	9.5 —	62.4 —	**226.8** **0.14**	19 1.0
CO	1-hour 8-hour	**1977** **348**	1069 178	6.5 —	36.5 —	134.7 5.7	2000 500
PM_{10}	24-hour annual	— —	— —	2.9 —	**3.2** —	2.94 **0.15**	5 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

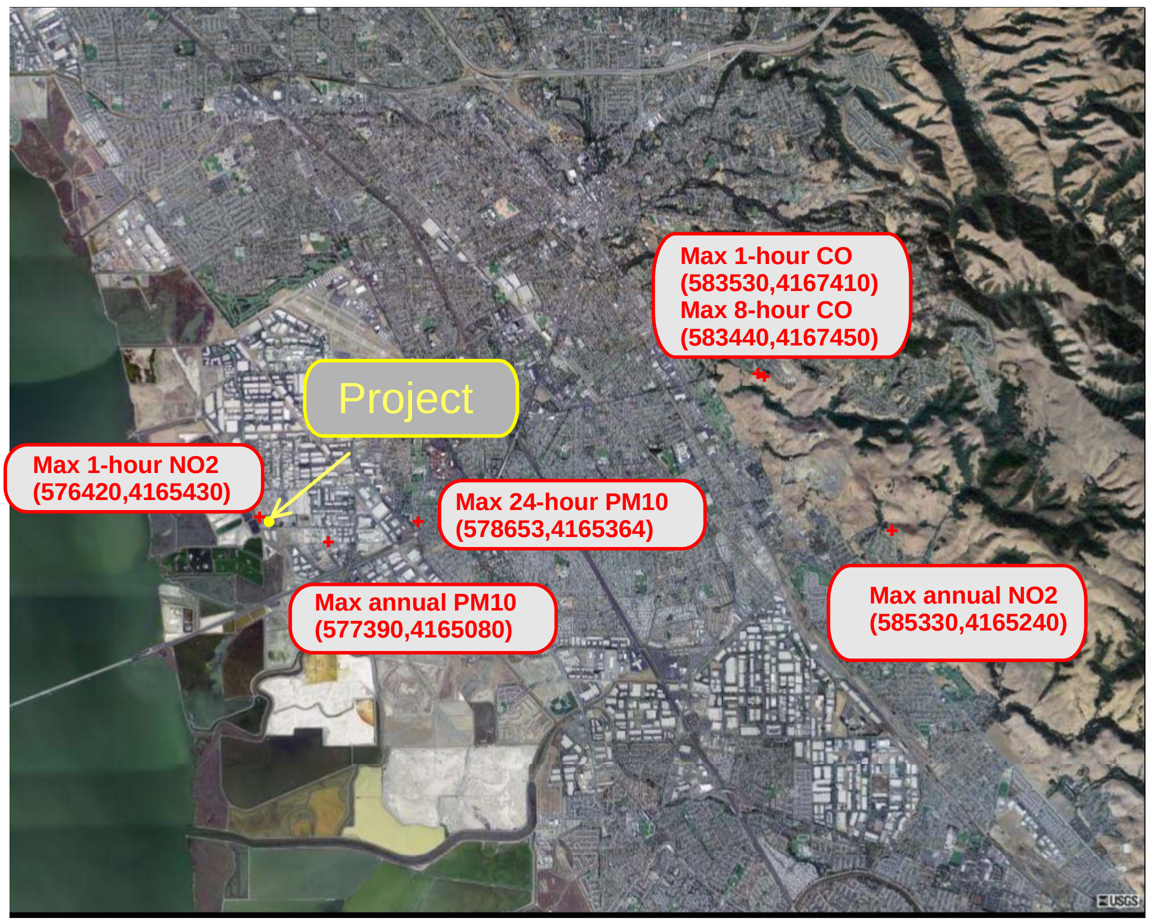


FIGURE 1. Location of project maximum impacts.

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

				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	$19,015	$52,746	$169,530
PE Total:				$256,704	$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 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, 0.13 x TCI	15 yrs - period	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

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 $SCONO_x$™.

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 2

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT
SINCE 1955

February 4, 2010

Rick Thomas
Vice President of Development
Calpine Corporation
4160 Dublin Boulevard
Dublin, CA 94568

APPLICATION NUMBER: 15487
PLANT NUMBER: 18136

FACILITY LOCATION: 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in the City of Hayward, Alameda County, California

Subject: Final PSD Permit for the Russell City Energy Center

Dear Applicant:

In accordance with the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act, and 40 C.F.R. Section 52.21, the Bay Area Air Quality Management District ("District") has issued a final Federal PSD Permit for the Russell City Energy Center, a 600 megawatt natural gas-fired combined cycle power plant to be located in Alameda County, California. A copy of the Federal PSD Permit is enclosed.

The Air District has issued this Federal PSD Permit after a comprehensive permitting review to ensure that the facility will comply with all requirements of the Federal PSD program under the Clean Air Act. The Air District summarized its analysis of the facility and how it will comply with applicable Federal PSD requirements in the Statement of Basis for this project, which the Air District published on December 8, 2008 along with its initial proposal to issue this permit. The Air District solicited public comment on the December 2008 Draft PSD Permit and accompanying Statement of Basis, and accepted written comments until February 6, 2009. The Air District also held a public hearing at Hayward City Hall to receive comments in person on January 21, 2009. Based on the comments received during this first comment period, as well as on additional review and analysis by Air District staff, the District revised its proposal. The Air District published a revised Draft PSD Permit on August 3, 2009, along with an Additional Statement of Basis summarizing the Air District's analysis on which the revised draft permit was based. The

Air District then held a second public comment period on the revised Draft PSD Permit, and accepted written comment until September 16, 2009. The Air District also held a second public hearing at Hayward City Hall on September 2, 2009.

The District has responded to all public comments it received on this permit in a Response to Comments document, which is available from the District upon request and on the District's website at www.baaqmd.gov. The PSD Permit, the Response to Comments, and all other relevant documents regarding this permit are available for public review and inspection at District headquarters.

Members of the public who participated in this permitting action and who are dissatisfied with the District's permitting action may appeal the permit to the Environmental Appeals Board pursuant to the appeal provisions of 40 C.F.R. Section 124.19. Any person who failed to file comments or to participate in a public hearing may appeal any changes that the District has made from the draft permit to the final permit. Any such members of the public must file any appeal no later than March 22, 2010. This date provides 45 days from permit issuance to file appeals, which is greater than the minimum 30 days required under 40 C.F.R. Part 124. Permit appeals must be actually received and filed with the Environmental Appeals Board no later than March 22, 2010, to be considered timely. More information regarding the EAB appeals process is available from the EAB at the following addresses or by telephone at (202) 233-0122:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
www.epa.gov/eab/

Pursuant to 40 C.F.R. Section 124.15(b)(1), this PSD Permit becomes effective March 22, 2010, unless an appeal is filed with the Environmental Appeals Board by that date period pursuant to 40 C.F.R. Section 124.19. If an appeal is filed, the PSD Permit does not become effective until the appeal is resolved.

Notice of this permitting action will be served by U.S. mail and/or e-mail on all persons who submitted written or oral comments during the public comment periods for this permit, and other interested persons and entities. Although not required for PSD permits, notice will also be provided by publication in at least one newspaper of general circulation in the area where the project is located, in keeping with the Air District's practice under state-law rules for issuing Authority to Construct permits.

Please include your application number with any correspondence with the District. If you have any questions regarding this matter, please contact Weyman Lee, P.E., Senior Air Quality Engineer, at weyman@baaqmd.gov, (415) 749-4796.

Very truly yours,

Brian Bateman
Director of Engineering

Enclosure: Final PSD Permit

Exhibit 3

Additional Statement of Basis

Draft Federal "Prevention of Significant Deterioration" Permit

Russell City Energy Center

Bay Area Air Quality Management District
Application Number 15487

August 3, 2009

Draft Federal PSD Permit
Additional Statement of Basis and
Solicitation of Further Public Comment
For the Proposed Russell City Energy Center

August 3, 2009

The Bay Area Air Quality Management District ("Air District") is revising its draft Federal PSD Permit for the proposed Russell City Energy Center based on new information received since the initial draft was published in December of 2008. Pursuant to 40 C.F.R. section 124.14(b), the Air District is incorporating this new information into this Federal PSD permit proceeding by:

(1) Issuing a revised draft permit with certain modifications to address new information under 40 C.F.R. section 124.6;

(2) Issuing an additional "Statement of Basis" for the draft permit under 40 C.F.R. sections 124.7 and 124.8[1]; and

(3) Reopening the comment period under 40 C.F.R. section 124.10 to give interested persons an opportunity to comment on the new information and the District's proposed treatment of it; and to give interested persons an opportunity to submit any further comments that they could not reasonably have submitted during the initial comment period.

This document contains the revised draft Federal PSD Permit conditions and the District's Additional Statement of Basis supporting them. The purpose of this Additional Statement of Basis is to briefly set forth additional facts and further factual, legal, methodological and policy questions that the Air District has considered regarding the draft permit since the initial Statement of Basis was issued. The document briefly describes the derivation of the current revisions to the draft permit conditions and the reasons for them. The Additional Statement of Basis provides further documentation regarding the Air District's proposed decision to issue the Federal PSD Permit in order to provide the public a further opportunity to comment on it. The Air District has prepared this Additional Statement of Basis because it has undertaken additional analysis and consideration regarding this proposed project since the initial Statement of Basis was issued. This additional analysis and consideration was undertaken for several reasons, including recent changes in the Federal PSD regulatory environment, additional factual information that has become available since the initial Statement of Basis was prepared, insightful comments received from members of the public during the initial comment period, and further discussions with the project applicant. The Air District believes that this additional analysis and consideration, as well as the revised draft permit conditions that have come out of it, will result in an improved permit.

[1] As with the initial Statement of Basis, the Air District calls this document a "Statement of Basis", but has prepared it in accordance with all of the comprehensive requirements for documenting the agency's analysis contained in 40 C.F.R. Sections 124.7 (statement of basis) and 124.8 (fact sheet). *See* Statement of Basis, p. 3 fn. 1, for further discussion.

The Air District invites all interested members of the public to review the Revised Draft Federal PSD Permit and Additional Statement of Basis and submit comments on the issues raised in them. To assist the public in doing so, the Air District is making a number of materials available so that the public may review them and learn more about the proposed permit. This Additional Statement of Basis, the initial Statement of Basis published in December of 2008, the revised proposed permit conditions, the initial permit application and all subsequent data and information submitted by the applicant, and all other materials supporting the Air District's proposal to issue the Federal PSD Permit are available for public inspection at the Outreach and Incentives Division Office located on the 5th Floor of District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. The Additional Statement of Basis and revised proposed permit conditions, as well as the initial Statement of Basis and initial proposed permit conditions, are also available on the District's website at www.baaqmd.gov. The public may also contact Weyman Lee, P.E., Senior Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4796, weyman@baaqmd.gov, for further information. **Para obtener la información en español, comuníquese con Brenda Cabral en la sede del Distrito, (415) 749-4686, bcabral@baaqmd.gov.**

The Air District invites all interested members of the public to submit written and/or oral comment on any issues raised by this revised Draft Federal PSD Permit and Additional Statement of Basis. Written comment should be directed to Weyman Lee at the contact address provided above, and must be received by September 16, 2009. Oral comments may be submitted at the public hearing the Air District will be holding for this project. The public hearing will be held at Hayward City Hall, 777 B Street, Hayward, CA, 94541, on Wednesday, September 2, 2009, from 6:30 to 9:00 pm. Air District staff will be available from 6:00 to 6:30 to discuss the project informally and answer questions.

The Air District also invites all interested members of the public to submit written and/or oral comment on any issues regarding the initial draft permit and statement of basis that were published in December of 2008 that members of the public were not able to comment on during the initial comment period (which closed on February 6, 2009). To the extent that members of the public have comments regarding the initial draft permit and statement of basis that they could not reasonably have made during the initial comment period (for example, because of evidence or information that was not reasonably ascertainable during the initial comment period, because of changes in regulatory requirements since that time, *etc.*), the Air District invites them to be submitted during this additional comment period (either in writing addressed to Mr. Lee or orally at the public hearing) so that the Air District can consider them before making a final decision on the proposed permit.

Members of the public who submitted comments during the initial comment period on the initial draft permit and statement of basis **do not** need to re-submit their comments to the Air District. The Air District has taken all comments previously received during the comment period under consideration and will consider and respond to them before making a final decision on the proposed permit. Persons who submitted comments earlier may of course provide additional comments during the current comment period on any relevant issues.

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<u>ADDITIONAL STATEMENT OF BASIS</u>

The Air District's additional analysis and consideration of the Federal PSD requirements as they apply to the proposed Russell City Energy Center are described in this section. This additional analysis builds on and refines the analysis set forth in the initial Statement of Basis issued in December of 2008, which is incorporated herein by reference. The draft PSD Permit conditions based on this analysis are set forth at the end of this document.

I. PROPOSAL TO ISSUE FEDERAL PSD PERMIT FOR RUSSELL CITY ENERGY CENTER

At the outset, the Air District wishes to clarify that it is now proposing to issue a new Federal PSD Permit for the Russell City Energy Center, not an amendment to an existing Federal PSD Permit as the District originally proposed. The Air District has reviewed the permitting record since it issued its original proposal in light of comments received during the initial comment period. Based on this review, the District has concluded that when the facility was initially permitted in 2002, the District did not issue a final Federal PSD Permit along with its state-law Authority to Construct, as is the District's normal practice. The record indicates that the District did not finalize the Federal PSD Permit at the time it issued the Authority to Construct because EPA Region 9 had not completed its Endangered Species Act consultation with the US Fish & Wildlife Service. The project applicant subsequently withdrew its plans to build the facility at the original location, however, and so the consultation was never finalized and the Federal PSD Permit was never issued.

The Air District is therefore revising its initial proposal to issue an "Amended Federal PSD Permit". The Air District is now proposing to issue a new Federal PSD Permit for this facility, since no final PSD Permit has yet been issued. The Air District has reviewed its analysis in the initial Statement of Basis and has concluded that this analysis supports the issuance of all elements of the permit as a new permit, because the Air District treated the facility's permit application, in substance, as an application for a new permit rather than as an application for an amendment. In evaluating the project for compliance with Federal PSD requirements, the Air District did not rely in any way on the analysis prepared for the initial permit. To the contrary, the Air District made clear in the Statement of Basis that it was evaluating the <u>entire project</u> for compliance with the Federal PSD requirements, not just elements that were changing since the initial permitting. As the Air District explained in the Statement of Basis, it analyzed both the amendments to the proposed project as well as the elements that were not being changed, and concluded "[t]he analysis of the elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standard for Federal PSD Permit, and that they would *comply with current PSD requirements even if they were being proposed anew at this time*." (Statement of Basis at p. 7 (emphasis added).) The detailed analyses provided in the Statement of Basis support this conclusion. The Air District evaluated all of the equipment at the project from scratch to ensure that it meets current BACT standards as is required for a new permit application. The District similarly conducted an Air Quality Impacts Analysis (and related analyses) from scratch for the entire project, using the most current information and modeling techniques, as is required for a new project. Those analyses, along with the additional review and analysis described in this document, fully support the issuance of a new Federal PSD Permit as the District is now proposing to do.

The Air District provides this discussion to clarify in the record at this point that it is proposing to issue a new permit, not an amendment to an existing PSD permit. To the extent that there were any issues involving the District's proposal that any members of the public refrained from commenting on during the initial comment period because they understood the proposed permit to be an amendment and not a new permit, the Air District invites the public to submit any such comments for the District's consideration at this time.

II. ISSUES REGARDING THE POWER GENERATION EQUIPMENT PROPOSED FOR THIS FACILITY

The Air District has conducted further analysis regarding the electrical generating equipment that the applicant proposes to use at the Russell City Energy Center and whether it is appropriate for this facility under the Federal PSD regulations. These issues are discussed below.

A. Currentness of Combustion Turbine Technology

The District received a number of comments regarding the type of electrical generating equipment the applicant intends to use at the Russell City Energy Center, and in particular whether it will be the cleanest and most efficient equipment consistent with the Best Available Control Technology requirements of the Federal PSD permitting program. Some of these comments stated that the Air District incorrectly based its BACT analysis for the combustion turbines/heat recovery boilers on the equipment that the applicant has already purchased and intends to use at the facility. Some comments questioned whether other equipment besides what the applicant intends to use for the project would be able to achieve lower emission rates. Although many of these comments were specific to emissions of individual PSD-regulated pollutants (or potentially PSD-regulated pollutants such as greenhouse gases), a number of them were directed at whether alternative equipment might be cleaner and more efficient in general. In response to these comments, the Air District explored whether there was more efficient generating equipment that the facility could use.

The Air District has identified "FD3" turbine technology as the current state-of-the-art electrical generating equipment for a facility of this type, as outlined in detail in Section III below. FD3 turbine technology would allow the facility to achieve an overall thermal efficiency of 56.4% (lower heating value), which is the highest efficiency of any similar plant that the Air District reviewed. This FD3 technology is slightly more efficient than the "FD2" technology that the applicant originally proposed. After further discussions with the project applicant, the applicant has agreed to upgrade its equipment to incorporate the more modern FD3 technology. These FD3 upgrades will result in an improvement in the thermal performance of the gas turbines, resulting in a slightly higher efficiency for the plant as a whole. That is, they will result in a reduction in the plant's "heat rate", which is the amount of fuel required to produce a megawatt (MW) of electricity, making the gas turbine's efficiency comparable to the best F-Class turbines available on the market today. The Air District is basing its BACT determinations on this state-of-the-art technology, not on the FD2 technology used in the turbines that the applicant originally proposed.

The FD3 upgrades will consist of decreasing the clearances in the compressor section of the turbine, adjusting the inlet guide vanes and optimizing the control system components. More specifically, the upgrades will include the following:

- The inlet guide vanes will be opened more to increase airflow.
- The existing compressor row 7-15 diaphragm inter-stage labyrinth seal holders will be replaced with honeycomb seals.

- The compressor row 16 blades will be replaced with a new design.
- The gas turbine row 1 blades will be replaced with a new design.
- The gas turbine row 1 ring segments and isolation rings will be replaced with a new improved design.
- The gas turbine row 2 seal housing will be replaced with a new rope seal.
- The gas turbine rows 2 and 3 vane sealing will be enhanced.
- The gas turbine row 4 blade ring assembly, consisting of blade rings, vanes, ring segments and inter-stage seal housing will be replaced with a new design.
- The gas turbine row 4 blades will be replaced with a new design.
- The existing exhaust cylinder will be replaced.

The Applicant will also implement operational and maintenance changes recommended by the original equipment manufacturer to improve performance, reliability and maintainability of the equipment. In addition, the Applicant will replace the control system with Siemens' latest control technology, known as the "T-3000" system.[2]

With these upgrades, the turbines the applicant has already purchased will, for all emissions performance purposes, be the equivalent of FD3 turbines commercially available today. These upgrades will increase the plant's overall efficiency, such that the rate of emissions per unit of energy produced will be reduced, which will allow the facility to meet a BACT standard set by the emissions rate achievable by FD3 turbines. Based on this FD3 technology, the facility will be able to achieve a thermal efficiency of 56.4%, which is the highest efficiency of any similar plant the Air District reviewed. This highly efficient technology will generate fewer emissions for a given amount of power generation than any other similar facility. The Air District is basing its proposed BACT permit conditions on this current technology.[3]

Furthermore, to clarify the record on this issue, Air District notes that it is basing its proposed BACT permit conditions on the emissions performance of this FD3-level technology, but is not proposing permit requirements specifying exactly what equipment must be used to satisfy the applicable BACT permit limits. BACT requires emission limits to be imposed based on the best emissions performance achievable by current state-of-the-art technology, but once the BACT limits are established based on this technology as the Air District is proposing, the specific

[2] *See* Email Memorandum re "RCEC: GHGs BACT Analysis Technical Documentation", from K. Poloncarz, Calpine Counsel, to A. Crockett, BAAQMD, April 2, 2009.

[3] The BACT analyses for certain specific pollutants and/or specific operating scenarios depend on other factors such as the availability of add-on controls, *etc*. But to the extent that emissions performance is linked to turbine efficiency, the emissions performance from these FD3-equivalent turbines will be the lowest achievable because FD3 turbines are the most efficient for this type of application. The gist of the comments the Air District received regarding turbine efficiency were primarily directed at greenhouse gases (to the extent that these are regulated NSR pollutants subject to BACT), but this same analysis holds true for the other pollutants, which are also dependent to some extent on turbine efficiency (*i.e.*, how much power can be generated for a given amount of fuel).

equipment the facility uses to achieve that limitation is irrelevant. As long as the facility keeps emissions within the BACT emission standards, it does not matter what particular choice of equipment the facility uses to do so. Certainly, from an environmental standpoint the choice is irrelevant because it is the emissions that impact air quality not the make or model of the equipment that generates them. If the applicant can meet current emission standards by upgrading existing equipment, there may be significant benefits to be gained, such as avoiding the costs of purchasing new equipment that would ultimately be borne by ratepayers and avoiding the waste inherent in junking serviceable equipment. But how the applicant meets current emission standards is up to the applicant. What matters from an air quality perspective – and what matters for purposes of the Federal PSD Permit requirements – is whether the limits established in the permit reflect the maximum emission reductions achievable for the source using current technology. As demonstrated in the Air District's BACT analyses (as set forth in more detail in the rest of this document), the limits the District is imposing on this facility are all based on current technology. Since the limits that the facility will be subject to are based on current technology, issues such as the date of manufacture or purchase of the specific equipment the applicant may choose to install are not relevant for purposes of the Federal PSD Permit.

B. Use of Duct Burners to Generate Additional Power

The District also received comments asserting that the proposed design of using duct burners to generate additional steam to power the steam turbine is not the most efficient method to generate additional power to meet peak demand. These comments asserted that duct burners are inefficient and reduce the fuel efficiency (and thus increase the air emissions) of the facility. They stated that the Air District should have considered alternatives to duct burners, such as simple-cycle turbines or solar alternatives, to meet peak load demand. In light of these comments, the Air District has considered further whether the use of duct burners satisfies the BACT requirement.

Upon further consideration, the District has concluded that there are no more efficient alternatives that would meet the power generation needs for which this facility was designed. The facility is designed to meet a maximum power demand of nominally 600 megawatts, but a 2x1 combined-cycle facility without duct burning can meet a nominal demand of only 550 megawatts.[4] Duct burning is an efficient way of generating additional power to meet peak demand from the combustion turbine exhaust. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine.

[4] Combustion turbines come only in discrete size classes, and so it is not always possible to design a facility to meet the demand called for using turbines alone. Where it is not possible, some way of making up the additional capacity must be used. (Note that these are nominal capacities; actual power output from a specific facility at any given time depends on a large number of design and operational variables.) The facility's design capacity cannot be achieved here by use of a 2x1 turbine configuration alone without some additional peak power.

In response to these comments, the Air District evaluated whether the additional peak capacity could be more efficiently provided by other technologies besides duct burning.[5]

The Air District first evaluated the alternative of replacing the duct burners with simple-cycle generating technology (*i.e.*, "peaker" turbines) that could generate approximately the same amount of energy during peak demand periods. Simple-cycle turbines would not be more efficient than duct burning here, however. To the contrary, simple-cycle turbines of similar capacity would have a higher heat rate (i.e., take more fuel to produce a unit of power) than duct burning. The incremental additional heat rate using duct burning to generate peak capacity (rated at 46.3 MW) is 7,595 Btu/kWhr (LHV).[6] In comparison, a basic GE LM6000 gas turbine generator set, rated at 42.3 megawatts, would have a heat rate of 8,308 Btu/kWh (LHV); with additional features, a GE LM6000 Sprint ("Spray-Intercooled Turbine"), rated at 46.9 megawatts, would have a heat rate of 8,235 Btu/kWh (LHV).[7] Duct firing will therefore be a more efficient method of generating peak capacity than installation of the most efficient form of simple-cycle generation capacity the Air District is aware of. The Air District therefore concludes that the use of a simple-cycle turbine would not provide any advantage over duct burning.

Moreover, even if it were not for the superior performance of Russell City Energy Center's duct burners in comparison to an LM6000, replacement of duct burners with a separate simple-cycle unit would likely be eliminated from consideration as BACT based upon the significantly greater cost and ancillary environmental impacts. According to a report prepared by the California Energy Commission, the cost to replace the proposed Russell City Energy Center's peaking capacity with a simple cycle plant would be approximately $507.98 per MWhr for an investor-owned utility (IOU) plant or $647.28 per MWhr for a "merchant" plant.[8] In contrast, the total

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[5] It is not clear whether the BACT analysis requires a consideration of alternatives to duct firing to meet peak capacity demand. The BACT analysis is not intended to require the applicant to change its design from construction of a combined cycle to simple cycle facility or to eliminate and replace key elements of its design with different sources. (*See*, *e.g.*, *In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, 51-52 (EAB 2003) (finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility"); *see also In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32 (referencing the EAB's recognition in *In re Kendall New Century Development* that "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility").) This issue is moot here, however, as the Air District has concluded that there are no superior alternatives even if such an analysis were required.

[6] *See* Russell City Energy Center Heat Balance Diagrams.

[7] GE Aero Energy Products, brochure, LM6000 SPRINT™ Gas Turbine Generator Set, available at: www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf.

[8] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Final Staff Report, December 2007, CEC-200-2007-011-SF, at pp. 10, 12; available at: www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-

estimated cost for a 550-MW combined cycle plant with duct firing is approximately $95.59 or $103.52 per MWhr for an IOU or merchant plant, respectively;[9] whereas the cost for a combined cycle facility without duct firing is estimated for an IOU and merchant plant at $94.47 or $102.19 per MWhr, respectively.[10] In light of these estimates, the marginal cost associated with duct firing at a facility like the proposed Russell City Energy Center would appear substantially more favorable than the cost to replace its peak capacity with a separate simple-cycle unit. The Air District therefore concludes the cost of requiring simple-cycle peak power generation would be obviously excessive, and thus would not be required as BACT for this additional reason as well.

The Air District also examined the potential for using solar thermal technology as an alternative to using duct burners in response to this comment. The Air District reviewed the approach taken with the proposed Victorville 2 Hybrid Power Project, which utilizes solar technology to eliminate some of the need for duct burning to address peak demand. The Victorville Project will be a 570-MW facility located in the Mojave Desert and will consist of natural gas-fired, combined-cycle generating equipment integrated with solar thermal generating equipment. The solar thermal component of the Victorville "hybrid" Project will consist of a series of diurnal, single-axis-tracking parabolic trough solar collectors laid out in parallel rows aligned on a north-south horizontal axis. Each solar collector will track the sun from east to west to assure that it continuously reflects the greatest amount of sunlight possible onto a "linear receiver", which contains a heat transfer fluid that circulates through the receiver and returns to a series of heat exchangers, where it is used to generate high-pressure steam for two heat recovery steam generators (HRSGs). The solar thermal input is intended to provide approximately 10% of the power generated by the facility during peak periods. Use of solar thermal equipment is projected to increase the overall thermal efficiency of the combined-cycle plant from 52.7% to 59% (LHV) because it would allow the facility to reduce firing of the duct burners during peak periods and replace that peak capacity with the input from the solar thermal generating equipment.[11] In comparison to Victorville's 59% efficiency rating (LHV) during such periods, the Russell City Energy Center's efficiency rating would be 56.44% (LHV) during periods of duct burning.[12]

A solar alternative to duct burning would not be feasible for the Russell City facility, however, because there is far less available area at the project than in the Mojave Desert, and the compact site would not provide adequate space for installation of a solar collectors. To construct a solar thermal plant to replace some of the peak capacity from duct burning would need 275 acres of

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SF.PDF. An LM6000 is the equivalent of "Small Simple Cycle" (50 MW) in the Energy Commission's report. Dollar figures are given in nominal 2007 dollars.

[9] *Id.* at p. 12.

[10] *Id.* at p. 10.

[11] City of Victorville, *Application for Certification, Victorville 2 Hybrid Power Project*, February 28, 2007, at 2.1-2.14; available at www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/ (hereinafter, "Victorville 2 Application"). Again, it is not clear that the BACT requirement is intended to involve replacement of duct firing to meet peak capacity demand with a completely different type of facility design, but that issue is moot because the Air District has found that solar peaking capacity would not be feasible here.

[12] *See* Table, Comparison of FD3 Turbines with and without duct burner firing, prepared by Alex Prusi, P.E., Director of Engineering, Calpine, April 2, 2009.

land,[13] which would not be feasible given the space-constrained project site on the edge of the San Francisco Bay.[14] Redesigning the project to incorporate a solar system like Victorville's would therefore require the facility to be moved to another location, making it impossible to achieve the project objectives served by the current location, which include "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices",[15] and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[16] Requiring additional space to build a solar system would also eliminate the environmental benefits of locating adjacent to the City of Hayward's waste water treatment plant so the facility can recycle approximately 4 million gallons per day of effluent from the plant and eliminate discharges of that waste water to the San Francisco Bay, and of locating at a previously-developed brownfield site. For these reasons, the Air District has found that thermal solar peaking capacity is not an available alternative to reduce the facility's use of duct burning to generate peak capacity.

The Air District therefore concludes that none of these alternative methods to generate the additional peak capacity needed to meet the facility's design load would be required under a BACT analysis for this facility, even if one were required.

C. Design of Facility for Intermediate-to-Baseload Service

The District also received comments noting that the facility would be operated to meet contractual load and spot sale demand, and may not operate on a full-time, base-loaded basis. These comments questioned the anticipated operating mode of the proposed Russell City Energy Center, suggesting that if it were intended for load-following or other duty that would involve frequent startup and shutdown events, the Applicant should be required to construct a fast-start-capable, peaking-to-intermediate duty plant instead.

The Air District has considered this issue further in light of these comments. The Air District notes that the Federal PSD Permit process is designed to ensure that a proposed facility will be as low-emitting as possible (among other requirements). It is not designed to require an applicant to propose a different type of project of a different fundamental scope and design, for example to substitute a simple-cycle peaking plant instead of a combined-cycle intermediate-to-baseload

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[13] *See* Victorville 2 Application, *supra* note 11, at pp. 2-3.

[14] The project site for the Russell City Energy Center is a 14.7-acre area located in the West Industrial District of Hayward, California, adjacent to the City of Hayward Water Pollution Control Facility and near existing transmission facilities. *See* Calpine, *Application for Certification*, *Russell City Energy Center* (May 2001) (hereinafter, "RCEC Application for Certification"), at 9-3 – 9-4; available at: www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/vol-1/.

[15] California Energy Commission, *Commission Decision, Russell City Energy Center* (July 2002, P800-02-007) (hereinafter, "2002 Energy Commission Decision"), pp. 17 (available at: www.energy.ca.gov/sitingcases/russellcity/index.html).

[16] RCEC Application for Certification, *supra* note 14, at pp. 9-1 – 9-2.

project as the commenters suggest here.[17] Moreover, it would not make any sense from an emissions standpoint to require a simple-cycle facility for the purpose that this facility is intended to be used for, which is to serve intermediate-to-baseload capacity. Simple-cycle facilities are less efficient than combined-cycle facilities, which recover the heat from the turbine exhaust (which would simply be emitted and wasted in a simple-cycle facility) and use it to generate additional electricity. Simple-cycle facilities are therefore generally inferior to combined-cycle facilities, except for applications where the generating capacity must come on-line in a very short time frame, which is not the case with the uses for which this facility has been proposed and designed. The Air District therefore disagrees that it should require the applicant to redesign the facility as a simple-cycle peaking facility.

D. <u>Source of Emissions Estimates</u>

Some commenters also criticized the Air District for relying on emissions estimates from the project applicant and from the CEC in its explanation of the emissions from the project. The Air District believes that the project applicant and the CEC are among the best sources of information about potential emissions from the facility based on their detailed knowledge and understanding of the proposed project and the type of operation involved. Moreover, the Air District has not seen any suggestion that any of the emissions estimates the Air District relied on may be unreliable in any way, or that there may be alternative sources of emissions estimates that it should consider instead. And in any event, the Air District is proposing to turn the emissions estimates into enforceable emissions limits in the PSD permit, along with monitoring and recordkeeping requirements to ensure that actual emissions stay below these limits. Thus, if the underlying estimates turn out to be inaccurate and actual emissions exceed the estimates as they have been incorporated into the permit limits, the facility will be in violation of its permit and will have to shut down or curtail operations unless it can fix whatever problems are causing the increased emissions. For all of these reasons, the Air District disagrees that it is inappropriate to consider emissions estimates from the project applicant or from the CEC in its permitting analysis. In light of this reasoning, if any members of the public believe that there are alternative sources of emissions information that would be relevant to the PSD permitting process for this facility, the Air District seeks input on what those sources of information may be and how they may be relevant.

E. <u>Specific Turbine Information</u>

Finally, the District also received some comments asking for detailed information about the combustion turbines the applicant intends to use at the facility, such as turbine serial numbers, dates of manufacture, cost, *etc*. But specific details such as these are not relevant to determining the Best Available Control Technology and applicable permit limits for this equipment or for analyzing the potential air quality impacts of the facility, and so the Air District has not sought such information from Calpine. For example, if the Air District determines that a certain type of turbine technology is BACT and imposes a BACT permit limit based on the achievable

[17] This principle has been well established by the Environmental Appeals Board in reviewing PSD permits. *See, e.g.*, *In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32; *In re Kendall New Century Development, supra* note 5, at 51-52.

emissions performance for that turbine technology, it makes no difference which particular turbine is used (*e.g.*, which particular serial number) as long as the facility complies with the applicable permit conditions. The Air District therefore disagrees that such specific information about individual pieces of equipment is relevant to the Federal PSD Permitting analysis. To the extent that information about particular types of turbine technologies is relevant (*e.g.*, costs, ancillary environmental or energy impacts, relative efficiency, achievable emissions performance standards, *etc*.) the Air District has sought that information and provided it in the relevant sections of its permitting analysis. To the extent that members of the public believe that additional information would be relevant to the PSD Permitting analysis, the District solicits further comment on how it could be relevant and how it could impact the PSD permit process.

III. GREENHOUSE GAS EMISSIONS

Since the Air District initially prepared its voluntary Greenhouse Gas BACT analysis in December of 2008, it has substantially revised the analysis based on the many insightful comments it received and on additional analysis by District staff and submissions by the Applicant. The Air District's revisions to its voluntary Greenhouse Gas BACT analysis are described in detail below. The corresponding proposed permit conditions are included in the Draft Federal PSD permit conditions at the end of this document, based on the applicant's agreement to be subject to greenhouse gas BACT limits despite the lack of guidance from EPA that BACT limits are required under its PSD regulations.

A. Applicability Of PSD Permit Requirements To Greenhouse Gas Emissions

In the Statement of Basis, the Air District noted that the status of greenhouse gas regulation is not as well developed at the federal level, particularly under the federal PSD permitting program. This continues to be the case, although there have been several additional developments since the Air District published its initial proposal. A number of commenters claimed that these recent developments make greenhouse gases "subject to regulation" under the Clean Air Act, and that as a result they must be subject to PSD Permitting. The Air District is therefore recounting these developments in this Additional Statement of Basis to clarify the record on whether the Federal PSD regulations require consideration of Greenhouse Gases. Ultimately, however, whether PSD review of greenhouse gases is required under the Federal PSD permit program is a moot issue in this case, as the applicant has agreed voluntarily to subject itself to PSD review regardless of whether it is legally required or not.

As the Air District noted in the Statement of Basis, EPA's Environmental Appeals Board found in November of 2008 in the *Deseret Power* case that EPA as an agency has the discretion to determine whether greenhouse gases should be subject to PSD regulation or not, but had not at that time adopted any definitive policy position on the issue.[18] The EAB also suggested that it may be more appropriate for EPA to address this issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. The issue was thus in a highly unresolved state when the Air District issued its initial proposal on December 8, 2008. Then, on December 18, 2008, EPA issued a policy memorandum in response to the EAB's *Deseret Power* opinion. The impact of EPA's December 18 memorandum is that EPA is not requiring greenhouse gases to be regulated under the Federal PSD permitting program (at least not at this time).[19] The Sierra Club then petitioned for reconsideration of the December 18, 2008, memorandum claiming that it was an unlawful interpretation of the Federal PSD permit

[18] *See In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, slip op. at 63-65 (EAB Nov. 13, 2008).

[19] *See* Memorandum, Stephen L. Johnson, Administrator, *EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*, December 18, 2008; notice provided at 73 Fed. Reg. 80300 (Dec. 31, 2008).

requirements, and on February 17, 2009, EPA granted the petition for reconsideration.[20] As a consequence, EPA is now reconsidering whether greenhouse gases are subject to Federal PSD permit requirements, and will be soliciting public comment on the issue. As EPA explained in its February 17, 2009, letter, "PSD permitting authorities should not assume that the [December 18, 2008] memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." EPA declined to stay the effectiveness of the December 18, 2008, memorandum, however, and so that memorandum remains in effect as EPA policy for the time being.

Greenhouse gases are therefore currently not subject to Federal PSD Permit review pursuant to the December 18, 2008, memorandum because the memorandum has not been stayed. EPA has indicated that this interpretation is not necessarily "the final word" on the issue, however, and so greenhouse gases may become subject to Federal PSD permit requirements at some point in the future. The project applicant has therefore voluntarily agreed to go forward with the Air District's proposal to impose BACT permit limits on greenhouse gas emissions, so that the permit will satisfy PSD requirements for greenhouse gases in the event that they become subject to regulation in the future.

Several comments also stated that the Air District should impose greenhouse gas limits in the Federal PSD Permit under various authorities in California law. The District disagrees that it could impose greenhouse gas conditions under California law (or any other state-law conditions) in a federal PSD permit. It is certainly true that greenhouse gas issues are the subject of various California statutes and are being addressed by various California regulatory agencies, including the Air District, but that does not mean that the District can impose permit conditions under California law in a federal permit issued on behalf of the federal EPA.

Furthermore, the District also disagrees with assertions by certain commenters that the U.S. Supreme Court's decision in *Massachusetts v. EPA* means that greenhouse gases are "subject to regulation" under the Federal Clean Air Act. That case determined that greenhouse gases are within the definition of "air pollutant" as used in the Clean Air Act; it did not address the question of whether greenhouse gases are pollutants that are "subject to regulation" under the Clean Air Act.[21] Similarly, the Air District also disagrees that EPA's recent proposal to make a finding that greenhouse gases endanger public health and welfare[22] means that greenhouse gases are "subject to regulation". That proposal is not yet final, and even if EPA does finalize it as proposed the finding will not establish that greenhouse gases are subject to regulation under the PSD program. As EPA made clear in the proposal, that question will be answered in the reconsideration of the December 18, 2008, memorandum.[23]

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[20] *See* Letter, Lisa P. Jackson to David Bookbinder, February 17, 2009, available at: www.epa.gov/air/nsr/documents/ 20090217LPJlettertosierraclub.pdf.

[21] *See generally In re: Christian County Generation, LLC*, PSD Appeal No. 07-01, 13 E.A.D. __, slip op. at 7 n. 12 (EAB Jan. 28, 2008).

[22] *See* Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, US EPA (April 17, 2009), available at epa.gov/ climatechange/endangerment/downloads/GHGEndangermentProposal.pdf.

[23] *See id.* at n. 29.

In addition, after the close of the initial comment period, another issue was raised concerning greenhouse gases involving the potential for CO_2 emissions to contribute to increased ozone and particulate matter pollution in the vicinity where the CO_2 emissions occur. This issue was raised by recently-published research findings by Mark Z. Jacobson, a researcher at Stanford University, who has posited that locally-emitted CO_2 will form "domes" over urban areas where it is emitted, which will cause localized temperature increases under the "CO_2 domes", and the localized temperature increases will in turn increase the rate of formation of ozone and particulate matter in such areas.[24] The Air District notes that the concern expressed in this paper is similar to the general concern that has been expressed about greenhouse gases and the secondary pollution impacts that would arise from warmer temperatures on a global scale. This study is interesting in that it is the first time (that the Air District is aware of) that scientific research has focused on these issues on a local scale. With respect to whether the paper's findings mean that the Air District should treat greenhouse gases as pollutants "subject to regulation" for PSD permitting purposes, the Air District first notes that concerns about temperature increases from the greenhouse effect having secondary impacts on criteria pollutant formation have been known for some time, and yet have not led EPA to treat greenhouse gases as "subject to regulation" at this point as outlined above. The Air District is bound to follow EPA guidance with respect to the Federal PSD program, and so the Air District does not have the discretion to depart from EPA's position in response to a study such as this one. Moreover, since concerns about secondary pollutant effects from warming temperatures globally have not led EPA to consider greenhouse gases "subject to regulation" at this stage, it seems unlikely that consideration of such concerns on a local scale would do so either (at least, at this point in the evolution of EPA's approach to greenhouse gas regulation). This point is especially applicable here, where the first research supporting this hypothesis has only just emerged and there has not yet been time for a scientific consensus to develop around it. But in any event, as with all of these arguments about whether greenhouse gases should be considered "subject to regulation", the issue is moot in this case because the applicant has voluntarily agreed to have the Air District treat greenhouse gases as if they are regulated and to impose greenhouse gas BACT limits in the facility's PSD permit, as the Air District is proposing.

For all of these reasons, the Air District continues to regard the available guidance from EPA on this matter to direct that greenhouse gases are *not* "subject to regulation" under the Federal Clean Air Act and not legally required to be included in the Federal PSD Permit review. Nevertheless, since the District is treating greenhouse gases as subject to PSD permitting as discussed above, these issues are moot.

B. Greenhouse Gas BACT Technology Analysis For Combined-Cycle Power Generation Trains

The Air District has also conducted further analysis regarding the appropriate BACT standard for greenhouse gas emissions from combined-cycle intermediate-to-baseload combustion turbines, as explained in detail below. The District first looked at issues that have been raised about whether BACT requires an analysis of alternatives to fossil-fuel-fired combustion technology.

[24] *See The Enhancement of Local Air Pollution by Urban CO_2 Domes*, Mark Z. Jacobson, April 3, 2009, available at: www.stanford.edu/group/efmh/jacobson/PDF%20files/CO2loc0409.pdf.

The District next considered what emissions performance can be achieved by the most efficient combustion equipment available for the proposed facility here. Third, the Air District conducted additional analysis of what the most appropriate BACT permit conditions should be for such equipment, and as a result is substantially revising its proposed permit conditions.

1. Evaluation of Non-Fossil-Fuel-Fired Electrical Generation Alternatives

Of the comments the Air District has received so far, none has disagreed with the Air District's assessment that the only feasible control technology for reducing greenhouse gas emissions from fossil-fuel burning power generating facilities is to use the most efficient electrical generating technology,[25] and that at present there are no feasible post-combustion add-on controls for such facilities. The Air District did receive comments stating that the Air District should have evaluated alternative energy production methods that do not rely on fossil fuel combustion, however. These comments suggested that the District should not focus simply on turbine efficiency, as opposed to looking at more efficient ways of making electricity without using combustion turbines.

The Air District has considered these comments and is in agreement that the development of non-fossil-fuel electrical generating sources is of critical importance in meeting California's energy needs while at the same time furthering its air quality goals, especially in light of recent advances in the understanding of the problems posed by global climate change. The Air District recognizes, however, that alternative generating technologies are not currently capable of meeting the state's electrical power demand at all times and under all circumstances, and that some fossil-fuel generating capacity is still needed.[26] Determining the most appropriate mix of electrical generation sources under these circumstances is a highly complex engineering and policy exercise that is most appropriately undertaken by the California Energy Commission, the state's expert agency on energy policy matters. The Air District obviously has a supporting role to play in helping the Energy Commission to understand the air quality impacts of its siting decisions and to include appropriate air quality conditions in its licenses. But as an agency, the Air District does not have the expertise nor the authority to determine what type of generation sources are needed, of what capacity, and where. The Air District must therefore necessarily defer to the Energy Commission's decision that the proposed natural-gas fired, combined-cycle facility is the most appropriate alternative for this project. If it would be more appropriate to use wind or solar power to serve the function intended for the proposed Russell City project, the Energy Commission is the agency best suited – and specifically tasked by the California legislature – to make that determination.

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[25] Notably, one comment expressly stated agreement with the District's assessment that the only currently feasible control option for CO_2 is more efficient energy production.

[26] *See, e.g.*, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report prepared by MRW & Associates for the California Energy Commission (available at: www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF .

Here, the Energy Commission specifically evaluated potential non-fossil-fuel-fired alternatives, such as solar, wind, and biomass, in its licensing proceeding for the Russell City Energy Center. The Energy Commission ultimately rejected those alternatives as not feasible because "they do not fulfill a basic objective of the plant: to provide power from a baseload facility to meet the growing demands for reliable power in the San Francisco Bay Area."[27] The Energy Commission rejected wind and solar generating sources because of their inherently intermittent nature, which makes them inappropriate for a baseload generating resource intended to ensure an adequate supply of power in periods when solar and wind sources do not provide power to the grid.[28] The Energy Commission also noted that alternatives like wind and solar involve other environmental trade-offs that can offset the benefits of reduced air emissions. For example, the Energy Commission found that a "wind farm" capable of generating 600 megawatts of power would require 10,200 acres, approximately 690 times the amount of land needed for the Russell City project and associated facilities."[29] The Energy Commission similarly found that a solar thermal project would require approximately 3,000 acres, or over 200 times the amount of land needed for the Russell City project.[30] For all of these reasons, the Energy Commission determined that the better policy choice, taking into account all relevant factors, would be the facility as proposed and not a facility using alternative, non-fossil-fuel generating technology.[31] The Energy

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[27] 2002 Energy Commission Decision, *supra* note 15, at p. 19. The Energy Commission made a further finding in its 2007 Amendment decision that no renewable alternatives would be able to meet the project's objectives. *See* California Energy Commission, *Final Commission Decision, Russell City Energy Center* (October 2007) (hereinafter, "2007 Energy Commission Decision"), p. 21, finding 3 (available at www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF). In making this finding, the Commission relied in part upon the detailed analyses that were undertaken in connection with the original licensing proceeding in 2002. *See id*. at pp. 20-21.

[28] 2002 Energy Commission Decision, *supra* note 15, at p. 18.

[29] *Id*.

[30] *Id*.

[31] One alternative that the Energy Commission did not consider was coal-fired generating technologies. Some have argued that coal and natural gas should be considered alternatives of one another, and if this approach were taken then coal should be considered as an alternative along with wind, solar and biomass. To the extent that the Energy Commission even considered this issue, it is likely that it did not undertake a considered evaluation of a coal-fired alternative because in most respects natural gas is a far cleaner fuel. For example, the average emissions rate from existing coal-fired generation in the United States has been estimated by U.S. EPA at 2,249 lbs/MWh of CO_2. (*See* Environmental Protection Agency, *Air Emissions* (hereinafter EPA Air Emissions Summary), available at www.epa.gov/cleanrgy/energy-and-you/affect/air-emissions.html.) Other sources have estimated an average emissions rate over 2,300 lbs/MW-hr. (*See* California Air Resources Board, *Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01* (June 20, 2007), available at: www.arb.ca.gov/cc/ccei/presentations/OOS_EmissionFactors.pdf. Meanwhile, according to U.S. EPA, "[c]ompared to the average air emissions from coal-fired generation, [combustion of] natural gas produces half as much carbon dioxide," or about 1,135 lbs/MWh. (*See* EPA Air Emissions Summary, *supra*.) Other estimates put this number as low as 800 lbs/MWh. (*See* Pace, *Life Cycle Assessment of GHG Emissions*

Commission also considered biomass such as wood chips or agricultural waste as a fuel source, but found that such an alternative would not be feasible because no biomass fuel source is available in large enough quantities in the vicinity of the project.[32]

The Federal PSD BACT requirement is not designed to intrude upon this analysis by the expert state agency on power generation and supply policy. To the contrary, Federal PSD permitting explicitly contemplates that PSD permitting authorities will defer to other state agencies on siting decisions.[33] The Air District therefore disagrees that it should require a further review of alternative types of projects – even if they would involve fewer emissions – because that type of alternatives analysis is properly within the province of the Energy Commission's siting authority under the Warren-Alquist Act.

The Air District is of course cognizant of its obligation to provide a determination of what the Federal PSD BACT provision requires for a power plant like this one, in its role in advising the Energy Commission on Air Quality requirements. But the federal BACT framework is clear that it does not require consideration of the use of non-fossil-fuel-fired alternatives, and the Air District therefore could not suggest to the Energy Commission that such alternatives are required by the Federal PSD regulations, regardless of whether there are sound policy reasons to consider them. In determining the Best Available Control Technology for a proposed facility, EPA requires that the Air District examine the best technology for that particular type of facility. EPA requires that the Air District consider the purpose and basic design of the facility, and consider only control technologies consistent with that purpose and basic design. EPA has made clear that the BACT analysis should not include alternative technologies that would require the facility to undergo significant modifications that would alter its fundamental scope, or would change design elements inherent to the facility's purpose, or would call into question the existence of the facility, or would disrupt the applicant's basic business purpose for the proposed facility.[34] Here,

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from LNG and Coal Fired Generation Scenarios: Assumptions and Results, prepared for Center for Liquefied Natural Gas (Feb. 3, 2009) at p. 13; available at: www.energy.ca.gov/lng/documents/2009-02-03_LCA_ASSUMPTIONS_LNG_AND_COAL.PDF.) Even the most recent advanced coal generation technologies such as an integrated gasification combined-cycle (IGCC) coal-fired plant, which emits over 1,700 lb/MW-hr, would not come close to the emissions performance of natural gas. (*See id* at 11-12.) Any comparison of natural gas and coal as fuels would therefore find that natural gas is by far the preferable alternative.

[32] 2002 Energy Commission Decision, *supra* note 15, at p. 18.

[33] *See In re Prairie State Generating Co.*, PSD Appeal 05-05, *supra* note 5, slip op. at 44; *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 33 (EAB 1994); *In re EcoEléctrica, LP*, 7 E.A.D. 56, 74 (EAB 1997); *In re Kentucky Utils. Co.*, PSD Appeal No. 82-5, at 2 (Adm'r 1982).

[34] *See generally* Draft New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting US Environmental Protection Agency (October 1990) (hereinafter "NSR Workshop Manual"), at p. B.13; *In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32; *In re Kendall New Century Dev.*, *supra* note 5, at pp. 50-52 & n. 14; *In re Hillman Power Co.*, 10 E.A.D. 673, 691-92 (EAB 2002); *In re Knauf Fiber Glass, Gmbh*, 8 E.A.D. 121, 136 (EAB 1999); after remand, 9 E.A.D. 1, 8-11 (EAB 2000); *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 29-30 n.8 (EAB 1994); *In re Hawaii Commercial & Sugar Co.*, 4 E.A.D. 95, 99-100 (EAB 1992); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992).

non-fossil fuel technologies, such as wind and solar, would not be consistent with the facility's purpose and basic design. To the contrary, they would require a fundamental change in the facility's purpose – generating electric power from natural gas combustion – and would require a complete redesign of the basic elements of the facility. Moreover, changing to such technologies would likely call the existence of the facility into question, because it is far from clear whether wind or solar technologies could be used in lieu of combustion technology to meet the power generation demand the proposed facility will serve, according to the Energy Commission's findings discussed above. For all of these reasons, the BACT analysis is not required to consider such alternatives.

2. Evaluation of Most Efficient Combined-Cycle Combustion Turbine Technology

The Air District also received some comments that criticized the District's initial assessment that the Siemens-Westinghouse 501F turbines the applicant proposed for the project, which the District found to be 55.8% efficient, are the most efficient equipment available. Commenters stated that Siemens' new G-class turbines could be used to achieve a net plant efficiency of 58% and are already in operation at a number of plants. Commenters also stated that GE "H Class" turbines can achieve 60% efficiency, and have been in operation in Wales and Japan for some time. Commenters also claimed that the proposed Siemens F-Class turbines are at the bottom end of the 55.8-56.5% range found in similar turbines as evaluated in the Energy Commission's documents, and the Air District has not explained why more efficient turbines should not have been required.

Based on these comments, the Air District has further reviewed the types of gas turbine equipment available for this project to ensure that the facility will use the most efficient equipment. As noted above in Section II.A., the Air District found that recent advances in the Siemens F-class turbines have resulted in increased efficiency over the FD2 turbines that the applicant initially proposed. These FD3 upgrades can achieve a gross efficiency of 56.45% (LHV) for the combined-cycle facility (without duct burning), a small but significant increase over the 55.8% for the FD2 turbines as initially proposed. The Air District has therefore determined that an efficiency of 56.45% is achievable using FD3-equivalent technology, and is basing its revised greenhouse gas BACT analysis on this efficiency level.

Beyond the FD3-equivent technology, the Air District also examined the feasibility and potential emissions performance advantages of using next-generation turbine equipment such as G-Class or H-Class turbines at this facility. For G-Class turbines, this equipment would actually reduce the overall efficiency of the facility and increase greenhouse gas emissions per megawatt of power produced. This is because G-class turbines have a substantially greater power output than F-Class turbines. Thus, in order to build a 612-megawatt combined-cycle power plant as proposed here using G-Class turbines, the Applicant would need to use a substantially smaller steam turbine (143 MW) to provide the equivalent plant output, which is limited at 612.8 MW (net).[35] This would result in an inefficient bottoming cycle and would lower the overall plant

[35] *See* Table, Comparison of Plant Efficiency, 612.8 MW: FD2, FD3, G-Class and Flex 10 Configurations, Prepared by A. Prusi, Calpine, April 2, 2008. Siemens G-class turbines, when

gross efficiency rating to 49.8% (LHV), according to an analysis provided by the Applicant, compared to the 56.4% efficiency rating of the facility using the latest F-Class technology.[36] As a consequence, although the G-Class turbines may be marginally more efficient by themselves, when incorporated into a combined-cycle facility of this size they would result in lower efficiency for the facility as a whole. The Air District has therefore concluded that the use of G-class turbines would not be the top-ranked eliminated control technology here (i.e., would not lead to the most efficient plant), and would not constitute BACT.

As for H-Class turbines, that turbine class is not yet demonstrated and commercially available for the 60 Hz electrical power system used in the United States, and is therefore not a feasible control technology for purposes of the BACT analysis. GE does have an H-Class turbine that has been fairly well demonstrated for 50 Hz power systems used in other countries. It installed an initial 50 Hz technology validation project at Baglan Bay in Wales that has been in operation since 2003;[37] and it has a second 50 Hz project in Futtsu, Japan, that began operation in July 2008 (with a second turbine expected to come on-line in late 2009), which GE characterizes as "a key step in the commercial development of [the] H System gas turbine".[38] But GE's H-Class 60-Hz turbine is not as far along in the development process, and the company has only just installed its first 60-Hz H-class test turbine at the Inland Empire Energy Center in Riverside County, CA, which just began operation on January 28, 2009 (with a second turbine that is currently being installed but is not yet online).[39] This project will require extensive testing to ensure that it meets all design specifications and is sufficiently reliable for long-term

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initially introduced in 1999, had an output of 235 MW. (*See* E. Bancalari & P. Chan, Siemens AG, *Adaptation of the SGT6-6000G to a Dynamic Power Generation Market*, December 2005, at 12 (available at: www.powergeneration.siemens.com/news-events/technical-papers/gas-turbines-power-plants/index.htm#AdaptationoftheSGT6-6000GtoaDynamicPowerGenerationMarket).) Using two such turbines in a 2x1 configuration would require a 142.8 MW steam turbine to meet a 612.8 MW design capacity (235+235+142.8=612.8). This is a conservative estimate because current G-class turbines are even larger (*see id.*), which would necessitate an even smaller steam turbine and even less overall efficiency.

[36] *See* Table, Comparison of Plant Efficiency, 612.8 MW: FD2, FD3, G-Class and Flex 10 Configurations, *supra* note 35.

[37] GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* www.gepower.com/about/press/en/2007_press/121107b.htm; Frank J. Bartos P.E., *New, efficient industrial gas turbines coming: Siemens, GE, Full Report* Control Engineering, (August 8, 2008) (available at mobile.controleng.com/article/268171-New_efficient_industrial_gas_turbines_coming_Siemens_GE_full_report.php).

[38] Steve Bolze, Vice President-Power Generation, GE Energy, *quoted in* GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* www.gepower.com/about/press/en/2007_press/121107b.htm.

[39] *See* GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan*, supra note 37; Frank J. Bartos P.E., *The Hunt for 60%+ Thermal Efficiency*, Control Engineering (August 1, 2008) (available at www.controleng.com/article/CA6584899.html). The specific startup date for the Inland Empire project was provided by the applicant in communications in April of 2009.

operations,[40] and cannot be considered an available technology until this validation process is completed. As the Energy Commission noted in approving the installation of these H-Class turbines, the "install[ation], operat[ion] and test[ing of] this initial Frame 7H machine [is an] essential step in the development and marketing of this new product[.]"[41] The Air District has therefore concluded that H-Class turbines are not an available technology at the present time for this type of project.[42]

Based on this review, the Air District concludes that there is no other commercially available generating technology that would meet the needs of this project that would have a greater energy efficiency than the upgraded "FD3" turbines the applicant has proposed for use at the facility. The Air District also compared the 56.4% efficiency of this facility with other similar facilities in California that have been recently permitted or are currently undergoing review, and found it to be higher than any other comparable facility (with the exception of the Inland Empire Frame 7H demonstration turbines addressed above). The results of this comparison are summarized in Table 1 below.[43]

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[40] *See generally* Frank J. Bartos P.E., *supra* note 37 ("Extensive, predefined testing is necessary to ensure that turbine performance meets design specs, along with reliable, long-term operation associated with power systems. With several different technology levels being validated, the long development cycle needed for these turbines—from first firing through commercialization—becomes evident.").

[41] Memorandum, *Inland Empire Energy Center Power Project (01-AFC-17C) Staff Analysis Of Proposed Modifications To Change To GE 107H Combined-Cycle Systems, Increase Generation and Add Additional Laydown Areas*, From Connie Bruins, CEC Compliance Division Manager, to Interested Parties (Jun. 8, 2005) (hereinafter "Inland Empire Energy Center Staff Analysis Memorandum"), at p. iii. (available at: www.energy.ca.gov/sitingcases/inlandempire/compliance/2005-06-10_FINAL_ANALYSIS.PDF.) The Commission staff also observed that "as with any emerging technology, the proposed project involves a heightened risk of underperformance." *Id.* at p. 2.

[42] The Air District also examined Siemens technology in addition to GE. Siemens is also developing an H-Class product, but it is farther behind than GE. Siemens has installed a 50 Hz test project in Irsching, Germany, but it is currently validating the turbine in simple-cycle mode, with build-out of a combined-cycle configuration not planned until 2009-2011. (*See* Frank J. Bartos P.E., *Largest Gas Turbine: 2,838 Sensors, 90 GB Data Per Hour of Testing* Control Engineering, (February 13, 2009) (available at www.controleng.com/article/ca6637328.html?nid=2488&rid=1768760).) Siemens does not yet have a 60-Hz application installed anywhere in the world.

[43] The information in this table was taken from documents on the Energy Commission's website at www.energy.ca.gov.

Table 1: Comparison of Thermal Efficiency of Similar Combined-Cycle Power Plants

Facility	CEC Application Date	Facility Size (MW)	Thermal Efficiency (LHV)
Colusa Generation Station	11/6/2006	660	56%
Blythe Energy Project Phase II	2/19/2002	520	55-58% (est.)
Lodi Energy Center	9/10/2008	255	55.6%
CPV Vaca Station Power Plant	11/18/2008	660	55%
Victorville 2 Hybrid Power Project	2/28/2007	563	52.7% (w/ duct burn)
Avenal Energy Power Plant[44]	2/21/2008	600	50.5%
Palomar Energy Project	8/2003	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)
SMUD Consumnes Phase I	9/13/2001	500	55.1%

For all of these reasons, the Air District has determined that the 56.4% thermal efficiency proposed for the Russell City Energy Center is the best efficiency performance achievable from commercially available systems for a 600 MW combined-cycle power plant. The District invites members of the public to review and comment on this additional analysis regarding the most efficient generating equipment for the proposed facility with respect to greenhouse gases.

C. Expression Of BACT Emissions Limit In Permit Conditions

In addition to comments regarding the turbine technology that the applicant initially proposed for the facility, the Air District also received several comments critical of the District's proposal of a BACT limit for greenhouse gas emissions of 1100 lb/MW-hr. The commenters raised a number of related points in this regard.

- *Linkage Between lb/MW-hr* CO_2 *Emission Rates and Thermal Efficiency:* Some comments questioned the District's analysis of the range of lb/MW-hr CO_2 emissions performance levels among various turbines in the context of thermal efficiency. These comments referred to the fact that the BACT technology analysis was explained in terms of turbine thermal efficiency; yet when selecting the BACT performance level BACT was stated in terms of mass emissions per unit of power output. The commenters stated that the District had not explained how the range of turbine thermal efficiency percentages evaluated relates to the range of lb/MW-hr CO_2 emissions levels (although they stated that they presumed that the higher lb/MW-hr CO_2 emissions levels correspond to the less efficient turbines).
- *Use of Emissions Standard from SB 1368:* Commenters stated that the proposed 1100 lb/MW-hr permit limit was taken from SB 1368, and that it was developed in that context to accommodate existing facilities with older, higher-emitting equipment as well as new plants. The commenters claimed that this number can therefore at most be a floor for setting a BACT limit, and that it is not a measure of the best achievable performance.

[44] With respect to Avenal, one commenter stated that this proposed facility would be able to achieve a CO_2 emissions rate of 499.7 lb/MW-hr, but its calculation was based on estimated emissions at 50% load ("Case 12" in the table referenced by the commenter). At full load, emissions would be over 900 lb/MW-hr (using "Case 1") and a nominal power output of 600 MW based on the documentation cited by this commenter.

The commenters also claimed that the number was intended to apply to facilities state-wide, and it is not a case-specific determination of what a particular facility can achieve as required by BACT.

- *Data Showing Achievable Emissions ~800 lb/MW-hr:* The commenters stated that emissions data from new turbines show that current equipment should be able to achieve emissions as low as 800 lb/MW-hr. Commenters also stated that the District should look at the best achievable performance level of all turbines, including new turbines, and not limit its review to turbines that were built several years ago. Commenters also claimed that the District considered emissions data from only one year of operation from only two facilities, and should conduct a broader review.

- *Justification For Compliance Margin:* The commenters also criticized the District's claim that the BACT limit should be set at 1100 lb/MW-hr limit in order to provide a compliance margin. These commenters noted that 1100 lb/MW-hr is significantly higher than the emissions measured from the comparable facilities that the District examined (Metcalf and Delta). They asserted that the District should explain in more detail the need for a compliance margin and also the necessary magnitude of the margin. They claimed that the District should explain what foreseeable operating conditions might affect emissions performance, and provide data showing how much of a compliance margin these conditions would warrant.

- *Justification for Heat Input Limit:* One commenter framed its objection in terms of the heat input limit that the District derived from the 1100 lb/MW-hr emissions rate. The commenter noted that the corresponding heat input rate the District used as a BACT limit – 2944.3 mmBtu/hr – is 35% higher than what the rated maximum for the proposed turbines. The commenter objected that this approach would allow turbines with a much lower efficiency than the 55.8% level achievable by these turbines. The commenter claimed that this limit has no connection to actual emission rates achievable by such sources.

- *"Output-Based" Limit to Address Efficiency Changes Over Time:* Several commenters objected to the District's proposal to express the BACT limit for greenhouse gases as a limit on turbine heat input. These commenters claimed that instead of limiting heat input, the District should impose a limit on the mass of CO_2 emitted per MW-hr directly. The commenters claimed that if the limit is imposed on heat input only, emissions on a lb/MW-hr basis could rise if turbine efficiency declines because of maintenance issues, equipment modifications, or other reasons. Once commenter cited the *Steel Dynamics* EAB decision for the proposition that a BACT limit needs to ensure compliance on a continual basis over all levels of operation.

The Air District has reevaluated its proposed BACT emissions level in light these comments, and upon further consideration agrees that 1100 lb/MW-hr would not be an appropriate BACT limit for greenhouse gas emissions. Instead, the Air District is proposing a lower BACT emissions limit, as well as an "output-based" requirement for periodic compliance testing to ensure that the plant maintains the BACT efficiency standard over time. In particular, the Air District has adjusted its proposed BACT determination as follows.

- First, the Air District has focused its analysis of what emissions performance is achievable by generating equipment with a thermal efficiency at a BACT level of 56.4%. The Air District agrees with the comment that simply looking at lb/MW-hr numbers reported in the ARB database does not necessarily tie the analysis into thermal efficiency, which is the basis for the District's BACT analysis. Tying the analysis of the achievable numerical BACT emissions limitation to specific data about expected turbine performance is intended to address this issue. As explained below, for purposes of establishing an enforceable numerical efficiency limit the Air District has used heat input per unit of power output, in MMBtu/kWhr, as the appropriate metric for establishing the BACT limit because the objective, industry-standard method for measuring efficiency uses that metric.
- Second, the Air District agrees that using the 1100 lb/MW-hr number established for purposes of SB1368 as a performance standard for all turbines does not necessarily capture the best performance achievable by the most efficient turbines available for use in new projects, on which a BACT analysis should be based. Instead, the District has analyzed the greenhouse gas emissions that can be achieved by state-of-the-art FD3 class turbines, as noted above. The Air District has determined that the BACT emissions rate should be based upon a best achievable design base heat rate of 6852 Btu/kWhr (which is approximately equivalent to an emissions rate of 792-815 lb/MW-hr, depending on which emissions factor is used), with a reasonable compliance margin of a little over 12% to account for various factors that may make the best design performance unachievable during all operating scenarios over the life of the equipment. This compliance margin is based on a thorough analysis the various elements of turbine operation that may reduce turbine efficiency over time and thereby increase greenhouse gas emissions per unit of power output, as discussed in detail below.
- Third, the Air District agrees that the BACT limit as expressed in the permit needs to be "output based", instead of just an absolute limit on greenhouse gas emissions, in order to take into account the potential that maintenance issues may lead to declining efficiency. The Air District is therefore proposing to require both absolute mass emissions limits based on the amount of greenhouse gas emissions expected for combined-cycle turbines of this size and level of thermal efficiency, plus periodic compliance tests to ensure that the efficiency remains within the established BACT levels. The Air District is proposing to base the efficiency compliance test on an ASTM standard that measures heat rate per power output, which is a well-accepted engineering standard with objectively-defined measurement standards.

By adjusting its approach to the greenhouse gas BACT issue in this way, the Air District believes that its revised proposal will ensure a BACT standard that is based on the best achievable thermal efficiency of available equipment, with a reasonable and documented compliance margin to make sure it is as stringent as possible and still achievable across all operating scenarios. This revised approach also includes continuous short-term and long-term emissions monitoring as well as periodic efficiency monitoring to ensure that BACT performance does not unreasonably degrade over time because of maintenance lapses or similar concerns.

The Air District's revised analysis is set forth in full in the following sections. The Air District encourages all interested members of the public to review and comment on this revised analysis.

1. Conceptual Overview of Proposed Numerical Greenhouse Gas BACT Limits

The Air District is revising the draft Federal PSD Permit to incorporate two interrelated numerical BACT emissions limits for greenhouse gases. First, based on the Air District's technological analysis in the Statement of Basis and as further refined in this subsequent analysis, the Air District is proposing to adopt numerical greenhouse gas mass emissions limits based on the emissions expected from the facility's state-of-the-art electrical generating equipment. These proposed mass emissions limits are based on the maximum rated heat input capacity of the combustion turbines and HRSG duct burners needed to produce the power generation demand that the facility has been designed to serve. Every unit of heat input generates a known amount of greenhouse gas emissions, and so the Air District is proposing greenhouse gas mass emissions limits based on this heat input capacity, on an hourly, daily, and annual basis. The proposed heat input and greenhouse gas emissions limits the Air District is imposing are set forth in Table 2 below.

Table 2 - Proposed Heat Input and Greenhouse Gas Emissions Limit Summary

Averaging Period	Heat Input Limit (MMBtu)	Greenhouse Gas Emissions Limits (metric tons CO_2E)			
		CO_2	CH_4	N_2O	CO_2E
1-Hour	4,477.2	242	0.08	0.14	242
24-Hour	107,452.0	5,797	2.03	3.33	5,802
Annual	35,708,858.0	1,926,399	675	1,107.48	1,928,182

These proposed heat input and mass emissions limits are intended to ensure that the facility's turbines and HRSG duct burners will not use any more natural gas, and not have any more greenhouse gas emissions, than the Air District has determined is necessary to meet the design power generation capacity. As described in detail below, under this revised proposal the heat input and greenhouse gas emissions will be monitored in real time using natural gas usage information, which provides a very accurate indication of these parameters.

Second, the District is also proposing an "output-based" efficiency limit that takes into account the amount of power generated by the facility, in order to address the concern raised in comments that simply specifying maximum heat input and corresponding greenhouse gas output fails to address the potential that turbine efficiency may decline to the point where it no longer reflects BACT. The District is therefore proposing to impose a minimum turbine efficiency permit condition, expressed as MMBtu of heat input per megawatt of power output, that the facility will be required to achieve. The Air District is proposing to require the facility to conduct annual compliance tests in which heat input and power output are measured to a high degree of accuracy, and to ensure that gas turbine heat input remains below 7,730 Btu/kWHr (HHV), a rate equivalent to generating a minimum of one megawatt-hour of electric power per 7.73 MMBtu of natural gas burned.

The District is proposing this 7,730 Btu/kWHr (HHV) efficiency limit as the lowest heat input rate that can be reasonably assured under all operating scenarios. As outlined below, the limit was based upon the design efficiency of the 56.4% thermally-efficient FD3-equivalent combustion turbines[45] that the Air District has concluded are the BACT technology for a nominal 600-megawatt natural-gas fired combined-cycle electrical generating facility. This value, known as the "Design Base Heat Rate" for the facility, is 6,852 Btu/KW-hr (HHV), and reflects the thermal efficiency that the facility is designed for. To ensure that the numerical BACT efficiency limit reflects a reasonable margin of compliance, the District has evaluated the factors that could reasonably be expected to degrade the theoretical design efficiency of the turbines and increase the heat rate (*i.e.*, cause more fuel to be required to produce a megawatt of power). The Air District has considered a number of factors in this regard as explained in detail below, including (i) a reasonable design margin of 3.3% to reflect that the equipment as actually constructed and installed may not fully achieve the assumptions that went into the design calculations; (ii) a reasonable performance degradation margin of 6% to reflect reduced efficiency from normal wear and tear on the equipment between major maintenance overhauls; and (iii) an additional 3% degradation margin based on additional wear and tear caused by variability in the operation of the auxiliary plant equipment that will be powered by the turbines, including the natural gas compressors and water recycling system. These potential degradation factors are an unavoidable aspect of building and operating the facility, consistent with best engineering practices, and the ultimate BACT limit needs to account for them to ensure that it is achievable over all operating scenarios. Applying these potential degradation factors to the Design Base Heat Rate, the Air District has concluded that the appropriate numerical Greenhouse Gas BACT heat input efficiency limit for this equipment is 7,730 Btu/kWHr (HHV). The Air District is proposing this limit as an enforceable not-to-exceed permit limit, along with appropriate monitoring requirements.

In conducting this analysis, the Air District has also been mindful that under normal circumstances the establishment of a numerical BACT permit limit would often involve a review of permit limits imposed by other facilities and of monitoring data required under such permits. In this case, however, no facility the Air District is aware of has ever been subject to an enforceable BACT limit on its emissions of greenhouse gases; nor has any facility, to the Air District's knowledge, been subject to an enforceable limitation on its efficiency (heat rate per kW-hr of power output). Because this represents a "first of its kind" limitation in an air permit, there is little relevant performance data which might provide a basis for concluding that a lower Heat Rate Limit can consistently be met over time. An enforceable BACT limitation must be set at a level that the facility can achieve for the life of the facility, including as its equipment ages and incurs anticipated degradation. At the same time, the Air District believes the proposed Heat Rate Limit is stringent enough to assure that the facility operator will not allow the equipment to incur undue or extraordinary efficiency losses through deferral of necessary maintenance, such that the assumptions which supported this BACT determination are no longer valid.

2. Derivation of Numerical Greenhouse Gas BACT Limits

<u>Greenhouse Gas Mass Emissions Limits</u>: The Air District calculated the appropriate heat-rate limit and mass emissions rate limits using the maximum heat input capacity of gas turbines and duct burners combined (*i.e.*, at maximum plant capacity). The facility's maximum heat input

[45] The combustion turbine equipment on which the BACT heat rate analysis was based included the FD3 upgrades discussed above.

capacity is 4,477.2 MMBtu per hour; 107,452.0 MMBtu/day; and 35,708,858.0 per year. (*See* Proposed Permit Conditions 13, 14 & 15.) The Air District then calculated corresponding mass emissions rates for CO_2, CH_4, N_2O, and CO_2E using established emissions factors. For CO_2, emissions were calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, emissions were calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E was calculated by applying a global warming potential multiplier of 21 and 310 for CH_4 and N_2O, respectively, based upon the Air Resources Board's mandatory reporting rule.[46] The associated mass emissions limits are outlined in Table 2 above on an hourly, daily and annual basis.

Heat Rate Efficiency Limit: To determine the appropriate heat-input efficiency limit, the Air District started with the turbines' Design Base Heat Rate[47] and then calculated a reasonable compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions as noted above.

- ***Net Design Base Heat Rate – 6,852 Btu/kWhr:***

The turbines' Design Base Heat Rate is 6,852 Btu/kWhr (HHV), based on operation of both combustion turbines with no duct firing, corrected to ISO conditions.[48] (For comparison with a pounds-per-megawatt-hour efficiency rating, this is between 792.9 and 815.5 lbs/MWhr, depending upon which CO_2 emissions factor is applied.[49]) This represents what the plant (at the design stage) is expected to achieve when it is new and clean; it does not represent what it will achieve over time as the equipment incurs degradation between major maintenance overhauls. It also does not represent the equipment manufacturer's guaranteed levels of performance.

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[46] The Air District would also note that it is following the convention of stating emissions of greenhouse gases in terms of "CO_2-equivalents" (CO_2E), which, for this source, include emissions of methane (CH_4) and nitrous oxide (N_2O) as well. These two pollutants have a higher "global warming potential" than CO_2, reflecting their relative propensity to trap solar radiation within the Earth's atmosphere that would otherwise be reflected back into outer space and thereby contribute to global warming. The emissions factors and global warming potentials for N_2O and CH_4 are specified by the Air Resources Board's mandatory reporting rule: For N_2O, the emissions are 0.00022 lbs/MMBtu and the global warming potential is 310; for CH_4, the emissions are 0.0020 lbs/MMBtu and the global warming potential is 21.

[47] Electric generating facilities typically measure their efficiency in terms of the "heat rate", which is the energy content of the fuel, in British thermal units (Btu), that it takes to generate a kilowatt-hour (kW-hr) of electric power to the grid.

[48] *See* Russell City Energy Center Heat Balance Diagrams, *supra* note 6.

[49] The lower and higher figure reflect application of the emissions factors for CO_2 applicable under U.S. EPA's Climate Leaders program – 115.6 lb/MMBtu – and the Part 75 Acid Rain Monitoring Program, 118.9 lb/MMBtu. Other relevant emissions factors include the California Climate Action Registry's factor of 116.9 lb/MMBtu and the Air Resources Board's mandatory reporting rule, which applies emissions factors for CO_2 between 116.5 and 120.5 lb/MMBtu of natural gas, depending upon the Btu content of the gas stream.

Note that this Design Base Heat Rate of 6,852 Btu/kWhr (HHV) without duct firing and 6,970 Btu/kWhr (HHV) with duct firing reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant.[50] The total auxiliary load for this facility is 21.1 MW without duct firing or 24 MW with duct firing.[51] Accounting for this auxiliary load would result in a "gross" Design Base Heat Rate of 6,743 Btu/kWhr (HHV) when duct firing is not occurring, which would result in emissions between 780.3 and 802.5 lbs/MW-hr of CO_2E, depending upon which emissions factor is applied for CO_2. When duct firing is occurring, the "gross" Design Base Heat Rate would be 6,868 Btu/kWhr (HHV), or between 794.7 and 817.4 lbs/MWhr of CO_2E.

- ***Installed Design Base Heat Rate – 7,080 Btu/kWhr:***

While the Design Base Heat Rate reflects what the engineers aim to achieve in designing the facility, design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation. According to information provided by the Applicant, a design margin of up to 5% is typical in the commercial terms for the engineering, procurement and construction contracts for a combined-cycle power plant. Normally the performance guarantees from the combustion and steam turbine original equipment manufacturers and the contractual terms require demonstration that the project, as constructed, achieves the design output and heat rate, subject to a plus or minus 5% margin. For example, if the tested output is less than 95% of the guaranteed output, or the tested heat rate is more than 105% of the guaranteed heat rate, the original equipment manufacturer and engineering, procurement and construction contractor can declare substantial completion and pay liquidated damages to compensate for the performance shortfalls. The design margin also reflects some tolerance for uncertainties associated with the plant's auxiliary load, such as the potential variance between assumptions about the amount of load that will be required to conduct treatment and evaporation of the City's waste water within the facility, and actual experience. Adding this 3.3% design margin to the Design Base Heat Rate would result in an Installed Base Heat Rate of 7,080 Btu/kWhr (HHV), assuming dual unit operation without duct burner firing, corrected to ISO conditions.

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[50] This auxiliary load includes power for the facility's recycling of wastewater from the adjacent City of Hayward's wastewater treatment plant. This system will recycle roughly 4 million gallons of water a day in the facility's operations instead of having to obtain it from other sources; and will use a "Zero Liquid Discharge" system so that none of that wastewater will be discharged to the Bay. The facility also will include a "Low Noise/Plume-Abated" cooling tower, which will consume additional load due to use of recycled waste water. These are important environmentally beneficial aspects of the project.

[51] *See* Russell City Energy Center Heat Balance Diagrams, *supra* note 6.

- ***Degraded Base Heat Rate – 7,730 Btu/kWhr:***

To establish an enforceable BACT condition that can be achieved over the life of the facility, the Air District also must account for anticipated degradation of the equipment over time between regular maintenance cycles.

For the gas turbines, the Air District is basing its analysis on a 48,000-operating-hour degradation curve provided by Siemens, which reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5.2%.[52] According to combustion turbine manufacturers, anticipated degradation in heat rate of the gas turbines alone can be expected to increase non-linearly over time. The degradation curves relied upon by the Applicant describe the amount of "recoverable" and "non-recoverable" degradation. The former includes degradation that can be recovered through compressor water washing, filter changes, instrumentation calibration and auxiliary equipment maintenance. The latter includes degradation that cannot be restored upon a maintenance overhaul.

The 48,000-hour maintenance interval is based upon Siemens' recommendations, which provide detailed formulae for determining when the equipment should undergo certain inspection and maintenance activities, based upon the accumulated total for both "Equivalent Baseload Hours" and "Equivalent Starts".[53] By calculating Equivalent Baseload Hours and Equivalent Starts, the facility operator accounts for the specific operating conditions and events experienced by the facility that may impact the equipment's performance. These include the difference between baseload and peak firing hours and the impacts caused by instantaneous load changes (*i.e.*, outside of the expected ramp rate).

The original equipment manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, because the projected 5.2% degradation rate represents the *average*, and not the maximum or guaranteed, rate of degradation for the gas turbines, the Air District has determined that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate. A slightly higher than average expected degradation is justified for purposes of developing an enforceable emissions limit here, given the limited operational experience of the new FD3-level turbine technology. Adding this 6% degradation factor to the facility's "Installed Base Heat Rate" of 7,080 Btu/kWhr (HHV) (*i.e.*, the projected heat rate of the equipment in its original condition, after accounting for a predicted 3.3% design margin) would result in a potential heat rate of 7,505 Btu/kWhr (HHV) (without duct firing).

Finally, in addition to the heat rate degradation from normal wear and tear on the turbines, the Air District is also providing a reasonable compliance margin based on potential degradation in

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[52] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10 (July 15, 2008), Figure 3 "Degradation Effect on Gas Turbine Heat Rate" TT-DEG-76.

[53] Siemens Power Generation, Inc., Service Bulletin 36803, *Combustion Turbine Maintenance and Inspection Intervals*, Revision No. 10 (Oct. 7, 2004).

other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). These other elements include the following:

- *Variability in Natural Gas Pressure:* The facility needs to bring the natural gas burned in the turbines up to a pressure of 500 psi, and uses gas compressors to do so because the natural gas supplied to the facility is delivered at a lower pressure. According to data from PG&E, the natural gas supplier, the delivery pressure may fluctuate between 170 and 355 psi (or between 250 and 410 psi with upgrades to the natural gas line).[54] Because of the variability in delivery pressure, the gas compressor engines may have to cycle up and down, which can result in increased wear and tear on the engine and decreased fuel efficiency. This would increase auxiliary load on the facility and reduce overall plant efficiency.

- *Variability in Natural Gas Quality:* In addition to changes in natural gas pressure, the gas supply for the facility may also experience substantial variation in the quality of the natural gas (in terms of its chemical constituents). This can further exacerbate degradation of the gas turbines, in the same way that using low-quality gasoline can affect an automobile's performance.

- *Variability in Cooling Water Quality:* The facility's water recycling system will treat approximately 4 million gallons per day of waste water from the City of Hayward's adjacent treatment plant for use in the plant's operations. Data from the water treatment plant shows a substantial degree of variability in the water quality, which in some cases may require additional recycling of the water supply prior to its use by the facility.[55] The additional recycling would require greater load to conduct such treatment and could result in accelerated degradation of various components of the water treatment system, including pumps and rotating equipment. The same is true of the evaporator and Zero Liquid Discharge system, as well as of the plume-abated cooling towers.

- *Degradation in Turbine Exhaust Flow:* The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow of 3.75% over the 48,000 maintenance cycle.[56] This degradation in exhaust flow will result in a direct reduction in the ability of the steam turbine to generate power, which will further degrade the plant's overall efficiency. While degradation in the exhaust flow is expected to be partially offset by degradation in exhaust temperature (which rises over the maintenance cycle)[57], this offset will not make up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow.

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[54] Letter, Rodney Boschee, Pacific Gas & Electric, Wholesale Marketing & Business Development, to Chris Delaney, CPN Pipeline Company, subject: Calpine Russell City Energy Center, December 2, 2008.

[55] *See* City of Hayward Wastewater Treatment Plant water monitoring data, November 1, 2008 – March 20, 2009; Summary data, *Reclaimed Water Project-2008, Final Clarifier* for sample dated April 16, 2008.

[56] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, *supra* note 52, Figure 4 "Degradation Effect on Gas Turbine Exhaust Flow," TT-DEG-77.

[57] *Id*., Figure 5, "Degradation Effect on Gas Turbine Exhaust Temperature" TT-DEG-78.

- *Degradation in Steam Turbine Performance:* Degradation in the performance of the heat recovery boilers and steam turbine is also expected to occur over the course of a major maintenance cycle.
- *Degradation in Gas Turbine Performance:* The influence of the bay-side environment on the air inlet filter may cause inlet air pressure to be reduced, which would further degrade the performance of the gas turbines.

The Air District found little documentation on which to base a specific numerical estimate of exactly what the efficiency impacts would be from these affects, in part because regulatory agencies have not had to undertake analyses in this area before. Without usable precedents or documentation regarding the precise potential for degradation from these issues, the Air District has had to use its best engineering judgment to assess how much additional degradation should be anticipated. The Air District believes in its engineering judgment that an additional 3% degradation is a reasonable and appropriate estimate under the circumstances, taking into account the fact that the limits being imposed based on this estimate will be enforceable, not-to-exceed permit conditions. The Air District solicits further comment on this issue.

3. Implementation of Numerical Greenhouse Gas BACT Limits In Permit Conditions

Finally, the Air District is proposing to implement these greenhouse gas BACT limits as enforceable permit conditions, with appropriate monitoring and recordkeeping requirements. For the heat-input and GHG mass emissions limits, the Air District is proposing to require the facility to demonstrate compliance by monitoring its fuel usage on a real-time basis, and then calculating heat-input and mass emissions based on the fuel usage. For CO_2, mass emissions would be calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, mass emissions would be calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E would be calculated by multiplying CH_4 and N_2O emissions by their respective global warming potentials of 21 and 310, based upon the Air Resources Board's mandatory reporting rule, and then adding them to CO_2 emissions.[58] The facility would be required to maintain records of its heat input and mass emissions monitoring data in order to ensure compliance.

For the turbine efficiency limit (the 7,730 Btu/kWhr heat-rate limit), the Air District is proposing to require compliance testing to demonstrate compliance within 90 days after the end of the commissioning period (as defined in the permit) and annually thereafter to ensure that efficiency is maintained at a BACT level. Under this periodic compliance test requirement, the facility would be required to perform a "Heat Rate Performance Test" using the industry-accepted method for heat rate and capacity testing, the American Society of Mechanical Engineers (ASME) Performance Test Code on Overall Plant Performance (ASME PTC 46-1996)). This

[58] For purposes of assuring consistency with existing reporting regimes for greenhouse gas emissions, it makes best sense to align monitoring and reporting requirements in the Federal PSD Permit with these prevailing methods for calculation and inventorying of greenhouse gas emissions.

test includes objective parameters that will ensure consistent and reliable reporting of actual turbine efficiency, and it is the accepted industry standard test for this purpose. The facility would be required to conduct the test at baseload (*i.e.*, full capacity), without duct firing. The facility will be required to submit a test plan to the Air District for its review and approval at least thirty (30) days in advance of the proposed test. The test will consist of three one-hour test runs, and the results of each test run will be averaged and then corrected back to ISO conditions of:

- Ambient Dry Bulb Temperature: 59^{o}F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,866 Btu/lb
- Fuel HHV/LHV Ratio: 1.1099

To determine compliance with this condition, the result of this test will be compared to the Heat Rate Limit of 7,730 Btu/kWhr (HHV).

These compliance monitoring requirements will be effective to ensure compliance with the greenhouse gas limits in the permit. The Air District has also considered whether to require the facility to use a Continuous Emissions Monitor (CEM) to measure greenhouse gas emissions directly (as CO_2), but has concluded that calculating emissions from heat input is preferable. Unlike some other pollutants such as NOx or carbon monoxide whose formation is heavily dependent on conditions of combustion and/or performance of add-on emissions controls, greenhouse gases are a direct and unavoidable byproduct of the combustion process. The amount of carbon within the fuel will all ultimately be emitted as greenhouse gases in a manner that is easily determined using well-established emissions factors. One can therefore determine with great accuracy what greenhouse gases are being emitted by measuring the amount of hydrocarbon fuel being burned (measured as heat input). For this reason, the test methods for measuring heat rate and capacity can achieve an accuracy of ±1.5%,[59] which is better than the relative accuracy of CEMs which typically ranges as high as ±10%.[60] The Air District is therefore proposing to require surrogate monitoring for greenhouse gas emissions using heat rate instead of a CEM.

The Air District also considered whether it would be possible to monitor thermal efficiency on a continuous basis in terms of emissions (or heat input) per unit of power output, but found that it would not be feasible to measure efficiency in this manner on a continual basis in any meaningful way. Measuring efficiency with a high degree of accuracy requires expertly-administered test procedures as set forth in the ASME PTC 46 standard, and it is not feasible to require this testing methodology to be implemented at all times of facility operation. Moreover,

[59] American Society of Mechanical Engineers (ASME), *Performance Test Code on Overall Plant Performance*, (PTC 46-1996), October 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to a steam generator").

[60] *See, e.g.*, 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.")

measuring efficiency by comparing heat input to power output would not be feasible during periods such as startup, shutdown, or tuning when no power is being produced for the grid. There will be heat input during this period, but with no power output the denominator in the pounds-per-megawatt-hour efficiency measurement will be zero. And finally, thermal efficiency is unlikely to experience major ups and downs over time. Unlike NOx or CO, which could fall out of compliance rapidly if good combustion conditions are not maintained or if an add-on control device fails, thermal efficiency is likely to degrade relatively slowly over time.[61] A one-day snapshot of turbine efficiency from a periodic compliance test is therefore likely to be relatively representative of efficiency over a longer time frame. For all of these reasons, the Air District is proposing to require the facility to demonstrate compliance with the heat rate BACT limit through periodic compliance testing, not continuous monitoring. The Air District is proposing an annual test requirement, which is the typical test frequency the District requires in periodic monitoring situations such as this. Based on the performance degradation documentation the Air District has reviewed, annual compliance testing is an appropriate testing frequency for this type of permit limit.

D. Other Greenhouse Gas Emissions

The District has also undertaken a BACT analysis for greenhouse gas emissions from the diesel firepump engine and circuit breakers, which were not included in the greenhouse gas analysis in the initial Statement of Basis. This equipment has the potential to emit greenhouse gases, and in order for a greenhouse gas BACT analysis to be comprehensive it should include these sources as well. The Air District is therefore including the emergency diesel firepump engine and the circuit breakers in the voluntary greenhouse BACT analysis, and is proposing mandatory permit conditions to ensure that they are subject to enforceable BACT emission limits.[62] The Air District invites interested members of the public to comment on these elements of the BACT analysis.

1. Diesel Fire Pump

The emergency diesel firepump engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel, just as with the gas turbines and heat recovery boilers. There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis for the gas turbines. The Air District therefore concludes that the only achievable technological approach to reducing greenhouse gases from the firepump engine is to use the most efficient engine that meets the stringent National Fire Protection Association ("NFPA") standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types instrumentation and control and exhaust systems. (*See generally* Statement of Basis at pp. 55-56, describing the NFPA requirements.) As there is only one control technology to choose from, application of the 5 steps in the Top-Down BACT analysis results in the selection of that control technology.

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[61] *See generally* documentation regarding heat rate degradation cited in heat rate discussion above, pp. 31-33.
[62] The District received one comment stating that the greenhouse gas BACT analysis should also include the facility's pre-heater. This project does not involve a pre-heater.

The 2100 R.P.M. 300-hp Clarke JW6H-UF40 diesel firepump engine that the applicant has proposed for use here has a fuel consumption rate of 14.0 gallons per hour.[63] The Air District has reviewed fuel-efficiency data for similarly-sized NFPA-20 certified firepump diesel engines rated at 2100 R.P.M., and has not found any such engines with a higher fuel efficiency.[64] The Air District has therefore concluded that the 14-gal/hr Clarke engine is the most efficient equipment available, and so it qualifies as the BACT control technology.[65]

The firepump engine may have to be used for up to 50 hours per year for reliability testing and maintenance purposes. Use of the engine at 14 gallons of diesel fuel per hour for up to 50 hours per year would result in total greenhouse gas emissions from the fire pump of 7.6 tons CO_2E per year.[66] The Air District is therefore imposing a greenhouse gas limit in the permit of 7.6 tons per year of CO_2E as a BACT limit. The facility will be required to demonstrate compliance with this limit by recording fuel usage and using an emissions factor of 21.7 lb/ CO_2E-gal to determine resulting CO_2E emissions.

As with turbine emissions, the Air District considered using a CEM to monitor greenhouse gas emissions directly. But it concluded that determining emissions based on fuel usage as a surrogate is a preferable approach, for similar reasons as with the turbines. Fuel usage can be accurately measured, and the amount of greenhouse gas equivalents can be calculated precisely based on well-established emissions factors.

Finally, the Air District also received a comment suggesting that the District should impose conditions to ensure that the firepump engine is used only in emergency circumstances. The Air District notes that the engine also needs to be operated for short periods for testing, maintenance, and reliability purposes. The permit conditions as proposed explicitly limit operation to emergencies and for these specific, necessary non-emergency purposes.

2. Circuit Breakers

The facility's circuit breakers will also have the potential to emit a greenhouse gas, sulfur hexafluoride (SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks).[67] The Applicant's facility will include a switchyard with five circuit

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[63] *See* Clarke JW6H-UF40 Fire Pump Driver, Emission Data for California ATCM Tier 2, Clarke Fire Protection Products (Rev. E, July 12, 2007), at p.1.

[64] *Cf.* Cummins CFP11E-F10 Fire Pump Driver, California ATCM Tier 2 Emission Data (Aug. 26, 2008) (fuel consumption rate of 16.0 gal/hr); Deutz DFP6 1013 C25 fire protection engine, EPA Tier 2/CARB Technical Data Sheet (Apr. 2008) (fuel consumption rate 15 gal/hr).

[65] In the terminology of the "Top-Down" BACT analysis, the Clarke engine at 14.0 gal./hr would be ranked the No. 1 technically feasible control alternative at Step 3 of the analysis. Since the Air District is selecting the top technology, the additional steps in the analysis become moot.

[66] Unlike emissions of criteria pollutants, it is feasible here to impose a numerical emissions limitation for CO_2E because CO_2E has a direct correlation to fuel usage, which is readily measureable. The emissions factor for diesel fuel is 21.7 pounds of CO_2E per gallon.

[67] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse*

breakers, and the applicant has proposed breakers containing approximately 145 pounds of SF_6 each in an enclosed-pressure system.[68] SF_6, a gaseous dielectric used in the breakers, is a highly potent greenhouse gas, with a "global warming potential" over a 100-year period 23,900 times greater than carbon dioxide (CO_2).[69] Leakage is expected to be minimal, and is expected to occur only as a result of circuit interruption and at extremely low temperatures not anticipated in the Bay Area. Nevertheless, given SF_6's high global warming potential, even small amounts of leakage can be significant and should be considered for purposes of a greenhouse gas BACT analysis.

STEP 1: Identify Control Technologies for SF_6

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One alternative the Air District has considered is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. One alternative to SF_6 would be use of a dielectric oil or compressed air ("air blast") circuit breaker, which historically were used in high-voltage installations prior to the development of SF_6 breakers. This type of technology is feasible for use here, although SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities.[70]

Another alternative the Air District has considered is to use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year (by weight). In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

Gas Emissions Source, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada (June 2006), available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

[68] Alstom USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 10, 19.

[69] Letter, David, Mehl (California Air Resources Board, Manager, Energy Section), *Re: Sulfur Hexafluoride (SF6) Emissions Survey for the Electricity Sector and Particle Accelerator Operators*, January 13, 2009, available at: www.arb.ca.gov/cc/sf6elec/survey/surveycoverletter.pdf.

[70] *See* Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, November 1997 (hereinafter, "*NIST Technical Note 142"*), available at: www.epa.gov/electricpower-sf6/documents/new_report_final.pdf.

The Air District also considered the possibility of other emerging technologies that would replace SF_6 with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.

STEP 2: Eliminate Technically Infeasible Options

The Air District next examined the technical feasibility of each of the control alternatives identified. Looking at oil or air-blast circuit breakers, the Air District concluded that this alternative is not technically feasible for this project because it would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers.[71] The proposed project site does not have adequate space within the switchyard to accommodate oil or air-blast breakers. As previously noted, the project has been proposed for location in a densely populated area because, according to the Energy Commission, the project's objectives were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices", and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[72] As a consequence, replacement of the proposed circuit breakers with breakers that do not use SF_6 is not a feasible option for this Project, given the space constraints imposed by construction of the Project on a former industrial site near a source of recycled waste water.

As for the feasibility of enclosed-pressure SF_6 circuit breakers with leak detection, which are far smaller than oil/air-blast breakers for the same application, they are feasible for this location. The project proponent has proposed to use this equipment because of its performance benefits.

Finally, the Air District also evaluated the technical feasibility of emerging alternatives to SF_6. According to the most recent report released by the EPA SF_6 Partnership, "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[73] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications.[74] While some progress has reportedly been made using mixtures of SF_6 and other inert gases (*e.g.*, nitrogen or helium) in lower-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as

[71] Although the Air District's assessment is that oil and air-blast breakers are not feasible for this project, the District also conducted a BACT comparison between oil/air-blast breakers and SF6 breakers in Step 4 discussed below. The Air District has concluded that oil/air-blast breakers would be eliminated from the BACT analysis for two separate and independent reasons, because they are technically infeasible under Step 2 and because their ancillary impacts outweigh their net emission benefits under Step 4.

[72] 2002 Energy Commission Decision, *supra* note 15, at p. 17.

[73] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, December 2008, at p. 1 (available at www.epa.gov/electricpower-sf6).

[74] *See, e.g.*, NIST Technical Note 142, *supra* note 70; *see also* U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF_6", at 185; available at: www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf

an SF_6 substitute"[75] for high-voltage applications. The Air District therefore eliminated this alternative as technically infeasible.

STEP 3: Rank Control Technologies

The Air District then ranked the feasible control technologies. The most effective (and only) control technology that the Air District found to be technically feasible is to use state-of-the-art enclosed-pressure SF_6 circuit breakers. According to information from circuit breaker manufacturers, this equipment can be guaranteed to achieve a leak rate of 0.5% or less.[76] This leak rate meets the current maximum leak rate standard established by the International Electrotechnical Commission ("IEC").[77] This leak rate performance will be further enhanced by an alarm system to alert operators to potential leak problems as soon as they emerge.

Although the District found that oil/air-blast breakers would not be feasible for this particular project, the District nevertheless undertook a comparison between this alternative and the enclosed-pressure SF_6 alternative, which is outlined below. Oil/air-blast breakers would be the top-ranked alternative (with essentially no greenhouse gas emissions) if they had not been eliminated as infeasible. The District has undertaken this additional analysis to compare these two technologies, even though oil/air-blast breakers have already been eliminated, to see whether this alternative would be more attractive if it were feasible here.

STEP 4: Evaluate Most Effective Controls and Economic Impacts and Document Results

Step 4 of the top-down analysis involves consideration of the ancillary energy, environmental and economic impacts associated with using the top-ranked control technologies. Although the Air District eliminated oil/air-blast circuit breakers as not technically feasible at Stage 2 of the Top-Down analysis, the Air District has nevertheless compared that technology to SF_6 breakers to see how it would compare if it were feasible. This comparison shows that the use of the larger oil/air-blast breakers would have significant ancillary environmental impacts that would offset its greenhouse gas benefits, even if it were feasible. Oil/air-blast breakers would require additional land to be devoted to the project, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires. By contrast, according to the National Institute for Standards and Technology, SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads."[78] Accordingly, even if oil/air-blast breakers were not eliminated at Step 2 of the top-down analysis, they would not surpass the choice of SF_6 breakers in Step 4 because of their adverse ancillary environmental impacts.

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[75] Siemens TechTopics No. 53, *Use of SF_6 Gas in Medium Voltage Switchgear*, Siemens Power Transmission & Distribution, Inc. (June 3, 2005), (available at www.energy.siemens.com/cms/us/US_Products/CustomerSupport/TechTopicsApplicationNotes/Documents/TechTopics53Rev0.pdf), at p. 3.

[76] Email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.

[77] IEC Standard 62271-1, 2004.

[78] *NIST Technical Note 1425*, supra note 70, at p. 3.

STEP 5: Select BACT

Based on this top-down analysis, Air District concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. Breakers using oil or compressed air as a dielectric material are not technically feasible here because of their greatly increased size, and even if they were feasible the offsetting ancillary impacts would not preclude the choice of SF_6.

Select Appropriate BACT Emissions Limit

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is BACT should be able to maintain fugitive SF_6 emissions below 0.5% (by weight).[79] The Russell City Energy Center will require 5 breakers using 145 lbs. of SF_6 each, for a total inventory of 725 lbs SF_6. At a leak rate of 0.5%, annual SF_6 emissions would be a maximum of 3.6 lbs/year, which would equal approximately 39.3 metric tons CO_2E per year. The Air District is therefore incorporating an annual emissions limit of 39.3 metric tons CO_2E per year into the final permit.

Fugitive emissions are, by their nature, very difficult to monitor directly as they are not emitted from a discrete emissions point. Fugitive SF_6 emissions can be estimated very accurately, however, by measuring "top-ups", *i.e.*, the replacement of lost SF_6 with new product.[80] One can conservatively (and very accurately) assume that the amount of SF_6 that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full SF_6 level. The Air District is therefore not requiring monitoring of SF_6 fugitive emissions directly, but is instead requiring surrogate monitoring through measuring the amount of SF_6 lost and using a conversion factor to assess annual SF_6 fugitive emissions in terms of CO_2E. The facility will be required to calculate annual fugitive emissions in this manner to ensure compliance with the 39.3 metric ton CO_2E limit. These monitoring and recordkeeping requirements are consistent with the requirements in other regulatory approaches to the SF_6 fugitive emissions issue.[81]

In addition, as mentioned above, the Air District will require the use of an alarm system to alert controllers when a circuit breaker loses 10% of its SF_6. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial

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[79] IEC Standard 62271-1, 2004; email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.

[80] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, *supra* note 67, at p. 1.

[81] *See generally* California Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas emissions, 17 Cal. Code Regs. §§ 95100 *et seq*. (hereinafter, "Mandatory Reporting Rule") (available at: www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf). (Note that the Mandatory Reporting Rule contains a *de minimis* exemption that is not being included in the Federal PSD Permit reporting requirements.) The Mandatory Reporting Rule adopts the reporting protocol developed by EPA's SF_6 Partnership methodology, which requires tracking of the change in inventory, purchases/acquisitions and sales/disbursements of SF_6, and the change in total nameplate capacity. It also adopts the EPA SF_6 Partnership's reporting protocol form, which appears at Appendix A-21.

portion of the SF_6 escapes. The facility will also be required to investigate any alarms and take any necessary corrective action to address any problems.

E. Miscellaneous Greenhouse Gas Issues

The Air District has received comments stating that the District should include all greenhouse gas emissions in its BACT analysis, and not just CO_2. These comments specifically stated that the BACT analysis should include emissions of methane, N_2O, SF_6, and NH_3. In consideration of this comment, the Air District has ensured that its greenhouse gas BACT analyses do in fact take all greenhouse gases into account. The analyses and the associated emissions limits address greenhouse gases in terms of CO_2-equivalent emissions ("CO_2E"), which takes into account all greenhouse gases and provides a convenient measure for comparing the relative impacts of emissions from different sources. The Air District's analyses do not include NH_3 as a greenhouse gas, however, because it does not have a significant demonstrated potential for impacting climate change. If any members of the public continue to believe that NH_3 should be included as a greenhouse gas in these analyses, the Air District invites the public to submit additional comment as to why NH_3 should be considered a greenhouse gas.

The Air District also received comments stating that the "license should acknowledge the green house gas fees to be paid to the BAAQMD." These comments are correct that greenhouse gas emissions sources such as the proposed Russell City Energy Center will be subject to a permit fee that the Air District charges under its state-law authority to help defray the costs of its climate protection work, and the Air District acknowledges that here. But these fees are charged in connection with permit issuance and annual renewal, and are not established as permit conditions. There is no benefit from putting the fee requirement in the permit conditions, as the fees are enforceable and recoverable at the time when the permit is renewed each year. Moreover, these fees are not part of the federal PSD permit program, and so they would not belong in a Federal PSD permit in any event.

IV. NO_2 BACT ISSUES

The District also received several comments on its BACT analysis for NO_2. These comments are addressed in this section.

A. <u>Control Technology Comparison/Selection</u>

The Air District received several comments expressing a concern that some of the sources of information used to compare the energy and economic impacts of SCR and EMx control technologies are now several years old. For example, commenters questioned whether there may be some better method of estimating the costs of using an SCR control system than using the ONSITE SYCOM Energy Corp. cost analysis adjusted for inflation using the consumer price index; and whether it was appropriate for the District to rely on a study from 2000 in comparing the energy impacts of SCR and EMx control options.

The Air District continues to support its initial BACT analysis for NO_2, but would like to take this opportunity to clarify its analysis regarding these issues in the record. The Air District does not believe that any of the information it used to compare SCR and EMx as control technologies for NO_2 emissions is unreliable as a result of its age. With respect to the relative costs of the two technologies, some of the underlying information the Air District used in its analysis was several years old (although other sources were current), but the Air District adjusted those costs for inflation over that time period to obtain cost estimate information in current dollars. (*See* Statement of Basis at pp. 25-26 and fn. 19.) Adjusting costs for inflation in this way is a well-accepted method of estimating current costs, and the Air District has no reason to believe that these estimates are inaccurate. If any members of the pubic believe that these estimates are inaccurate, the Air District invites comment on how they are inaccurate. Moreover, if any members of the public believe that they have more accurate estimates, the Air District invites the public to submit their estimates during the comment period.

With respect to the analysis of ancillary energy and environmental impacts, these control technology alternatives have not changed in any significant way since the various sources of information cited in the Statement of Basis were published, and so there is no reason to doubt their current validity for purposes of the BACT comparison. Neither technology has changed in any significant way, and so attributes such as ammonia use, water consumption, and energy penalty implicit in these technologies have not changed in any significant way either. The Air District therefore does not find any reason to question the continued validity of the information it used in its energy and ancillary environmental impact comparison. If any members of the public believe that they have more accurate information in these areas, the Air District invites the public to submit this information during the further comment period.

Finally, the Air District notes that although the commenters have questioned the vintage of some of the sources of information that the Air District used in comparing these two technologies, the Air District did not receive any comments suggesting that its ultimate conclusion was incorrect: that neither of the two alternative technologies has any ancillary impacts significant enough to warrant elimination from consideration as a BACT technology. To the extent that any members of the public believe that the Air District should have used more accurate information in its analysis, the District invites the public to comment on how different information would have led to a different conclusion in the BACT analysis of these two technologies.[82]

B. Potential Risks From Ammonia Spills/Releases

As the Air District found in the initial Statement of Basis, the risks of accidental releases of ammonia from the SCR system are relatively minor and will be adequately addressed under applicable industrial safety codes and standards, given the safety requirements outlined in the Energy Commission's licensing documentation. (*See* Statement of Basis at p. 26 and fn. 20.) These safety measures include the Risk Management Plan requirement pursuant to Section 112(r) of the Clean Air Act and the California Accidental Release Prevention Program, which must include an off-site consequences analysis and appropriate mitigation measures; a requirement to implement a Safety Management Plan (SMP) for delivery of ammonia and other liquid hazardous materials; a requirement to instruct vendors delivering hazardous chemicals, including aqueous ammonia, to travel certain routes; a requirement to install ammonia sensors to detect the occurrence of any potential migration of ammonia vapors offsite; a requirement to use an ammonia tank that meets specific standards to reduce the potential for a release event; and a requirement to conduct a "Vulnerability Assessment" to address the potential security risk associated with storage and use of aqueous ammonia onsite. Given the relatively low risk of accidental releases and the additional safeguards provided by these measures, the District concluded that the potential for impacts from the use of ammonia in the SCR system was not significant enough to reject SCR as a control alternative. The Air District continues to believe that this position is the correct one based on all of the available information, and solicits further public comment on this issue to the extent that any members of the public disagree.

The Air District did receive comments during the initial comment period claiming that the CEC found that the there will be a significant risk of health impacts from an accidental ammonia spill, and that the Air District incorrectly characterized the CEC's findings on this point. The Air District would like to take this opportunity to clarify the record on this point. The Energy Commission expressly found that "[t]he Hazardous Materials Management aspects of the project do not create significant direct or cumulative environmental effects."[83] This finding was based (at least in part) on the conclusions of the CEC staff's Final Staff Assessment, which found that with the appropriate mitigation measures and safeguards against accidental releases, "impacts

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[82] One comment also questioned why, according to the Statement of Basis, it is "not known" whether Kawasaki Heavy Industries plans to make XONON technology available for other manufacturers' turbines, and whether the District should research this information further. The Air District has not researched whether XONON-brand catalytic combustors will be made available for other manufacturers' turbines because this type of combustion technology is available only for small turbine applications, and is not available for large-scale combustors used in large facilities such as this one. The Air District therefore concluded that this technology is not available as a BACT technology choice, making the issue of what manufacturers can provide the technology moot. If any members of the public believe that this is an issue that is relevant to the PSD Permit analysis, the Air District invites further comment as to why.

[83] 2007 Commission Decision, *supra* note 27, p. 115, Finding 3.

from the use and storage of hazardous materials [will be] less than significant."[84] Of course, if a major ammonia release was to occur, that situation would entail significant impacts. But the Energy Commission found that the safeguards in place to prevent and/or mitigate any accidental ammonia releases would adequately address this risk, and therefore that the overall impact from the use of ammonia at the facility would not be significant. This finding is consistent with the Air District's assessment in the Statement of Basis – that the potential for harm from accidental ammonia releases are not significant enough to rule out an SCR system using ammonia as a BACT technology. The commenters may have misunderstood the Air District's analysis on this point based on a sentence in the Statement of Basis that could be read to mean that the Air District believes that if an ammonia release occurred it would not have significant impacts. The Air District did not intend to take such a position, and agrees with the CEC and the commenters that an accidental ammonia release could potentially cause very significant impacts, and that this point is clear and indisputable regardless of any modeling that might be done. The Air District's conclusion in the Statement of Basis was that with the appropriate risk management requirements in place, the risk from the use of ammonia would not be significant enough to rule out SCR with ammonia use as a BACT alternative. The Air District invites any further comment that the public may have based on this analysis.

The Air District also received comments questioning whether the applicant has completed condition HAZ-2 of the CEC's conditions of certification (regarding preparation of a Risk Management Plan and Hazardous Materials Business Plan), and asking whether the District should review those plans in assessing the significance of the risks of a potential accidental ammonia releases. The Air District notes that this point that the detailed requirements for Risk Management Plans, Hazardous Materials Business Plans, and the other related hazardous materials safeguards are set forth in the applicable statutes and regulations that govern those plans. They are reviewed by the appropriate review bodies (*e.g.*, the hazardous materials division of the local fire department) before the facility begins operation. Those review bodies are the appropriate expert agencies to ensure that all of the applicable safeguards and precautions are in place. There Air District has no reason to believe that it should (or even could) conduct its own review to ensure that these safety requirements are being met. If any members of the public believe that the Air District cannot issue the Federal PSD Permit before the facility has completed these requirements (or before the District has reviewed them), the Air District solicits further comment as to why.

The Air District also received comments stating that if it does choose an SCR-type system, it should require the use of urea instead of ammonia in order to reduce the potential for impacts from accidental ammonia releases. The comments cited a technology called NOxOUT ULTRA that they claimed is feasible to allow the substitution of urea for ammonia. The NOxOUT ULTRA technology cited by the commenters generates ammonia from urea just before it is injected into the SCR system, which eliminates the need to store any significant amount of ammonia at the site. The elimination of ammonia storage would alleviate the risk of any significant amount of ammonia being released accidentally, and so it is worth evaluating as an

[84] California Energy Commission, *Russell City Energy Center, Staff Assessment – Part 1 and Part 2 Combined, Amendment No. 1 (01-AFC-7C)* (June 2007), CEC 700-2007-005-FSA, at pp. 4.4-5.

alternative technology. The Air District has considered this issue further in light of these comments and has concluded that requiring a urea SCR system over an ammonia system would not be the most appropriate BACT alternative. Although urea substitution could reduce the potential for accidental ammonia releases, the Air District has found that it would involve offsetting negative environmental impacts in the form of increased emissions of formaldehyde, a hazardous air pollutant and toxic air contaminant. The Air District reviewed data from a similar facility in Sumas, Washington, which demonstrated that urea injection (as opposed to the use of ammonia) resulted in a nearly five-fold increase in formaldehyde emissions.[85] These additional formaldehyde emissions, which would occur whenever the facility operates, substantially outweigh the benefits in further reducing the already low risk of a potential ammonia release event.

C. Secondary Particulate Impacts From Ammonia Slip

The Air District also received some comments suggesting that the potential for ammonia slip from the facility's NOx control equipment should be evaluated as a collateral environmental impact in terms of its potential for the ammonia slip to form secondary particulate matter. The Air District has considered that issue in detail as explained in the section on particulate matter emissions below. (*See* Section VI.C.) As explained there, the Air District has concluded that ammonia slip emissions are not a significant contributor to secondary particulate matter formation and thus are not a significant collateral environmental impact that would rule out the selection of SCR as a control technology for NO_2 compared with EMx technology.[86] The Air District examines collateral environmental impacts such as this on a case-by-case basis and does not have a bright-line rule for when a collateral impact would be considered "significant" or not. But certainly, in a case such as this one where the available evidence suggests that ammonia slip in fact will not cause significant secondary PM, the potential for such impacts would not be significant enough to eliminate a particular control technology.

D. NO_2 Permit Limits

The Air District also received a comment stating that the hourly BACT limit for NOx was updated in the 2007 permitting process, and was reduced from 2.5 ppm to 2.0 ppm, but the annual limit was not adjusted accordingly. In light of this comment, the District would like to clarify that the annual limit established in the 2002 permitting process was based on average annual emissions of 2.0. The Air District concluded during that permitting process that although short-term NOx emissions could be as much as 2.5 ppm, on average over the longer term they would not exceed 2.0 ppm. This new lower short-term limit represents a very stringent BACT

[85] *See* Valid Results, Inc., test report for June 13, 2002, EPA Method 316 Source Test (0.226 tpy formaldehyde emissions with urea); email message from Brian Fretwell to Barbara McBride, Calpine, March 4, 2009 (prior test without urea was 0.049 tpy formaldehyde emissions).

[86] The Air District notes that with respect to NOxOUT ULTRA, both SCR and NOxOUT ULTRA use ammonia in the NOx control reaction. The only difference with NOxOUT ULTRA is that it generates the ammonia from urea just prior to ammonia injection, so the facility does not have to store significant amounts of ammonia on-site. Ammonia emissions – as opposed to ammonia storage – is not a relevant issue in the comparison between these two technologies.

standard, and the Air District has no evidence to suggest that the facility will be able to maintain average emissions significantly below 2.0 over the long term. The Air District therefore used 2.0 ppm as the average emissions rate when calculating the annual facility NO_2 permit limit.

V. CARBON MONOXIDE BACT ISSUES

The Air District also received several comments on its BACT analysis for Carbon Monoxide suggesting that the CO BACT limit should be lower than the 4.0 ppm the Air District initially proposed. The Air District has reconsidered its BACT determination and is now proposing a lowered BACT limit for CO, at 2.0 ppm (1-hour average). The Air District reevaluated the operating data from the Metcalf Energy Center, which is a similar facility that the District looked to in its original analysis, and notes that the CEM data show that only 0.4% of the days of operation showed any exceedance of 2.0 ppm after the first year of operation. The Air District has concluded that a more critical analysis of this data suggests that it should be possible to design the system to ensure that Carbon Monoxide emissions are maintained below 2.0 ppm at all times.

The Air District also examined a number of other CO permit conditions for other facilities – many of which were pointed out in comments submitted during the initial comment period – and found that the consensus of permitting agencies around the country appears to be forming around a CO BACT limit of 2 ppm. The Air District notes that there were a total of 8 permits identified in the initial Statement of Basis with Carbon Monoxide limits of 2 ppm (either with 1-hour averages or 3-hour averages), suggesting an emerging consensus that this performance level is achievable. (*See* Statement of Basis, Table 11, pp. 32-33.) Based on this further assessment of the data, and on the large number of permitting agencies that have required other similar facilities to limit CO emissions to 2.0 ppm averaged over 1 hour, the Air District concludes that this 2.0 ppm limit (1-hour average) should be required here as BACT. If this limit is being applied and demonstrably achieved at other facilities, that fact supports a presumption that it is an achievable limitation at this facility for purposes of BACT.[87]

The Air District also considered whether it might be appropriate to impose a BACT CO limit below 2.0 ppm. The District notes that (as comments pointed out) permits have been issued containing Carbon Monoxide limits below 2.0 ppm for Kleen Energy Systems[88] and CPV Warren, suggesting that CO emission limits below 2.0 ppm may be achievable for certain facilities. The Air District notes that neither of these facilities has actually been built yet and so there is no operating data available on which to assess whether they will actually be able to meet these lower limits. This point, along with the fact that the consensus among other permitting

[87] The Air District disagrees with the comments that the mere issuance of a permit with a particular limit establishes that limit as BACT, without some further demonstration that the limit is achievable. A permitting agency may issue permits with very stringent limits with little or no technical justification at all if the applicant does not object to it. In such a situation, where there is no justification for the limit nor any operating data to show that the limit can be complied with, the mere existence of the permit limit would not, without more, establish that the limit is achievable as a technical matter. But this point is moot here, as the Air District has reviewed data and conducted a detailed analysis and has on this bases concluded that the 2.0 ppm limit is achievable as BACT.

[88] New Source Review Permit to Construct and Operate a Stationary Source, issued to Kleen Energy Systems, LLC, by Connecticut Department of Environmental Protection, Bureau of Air Management, February 25, 2008.

agencies appears to have coalesced around 2.0 for most facilities, underscores the requirement that lower limits must be considered on a case-by-case basis. The Air District has therefore evaluated whether a CO emissions limit of less than 2.0 ppm would be achievable by this particular facility, "taking into account energy, environmental and economic impacts and other costs" as is required in establishing a BACT limit.

To undertake this analysis, the Air District evaluated information from the applicant on the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining emissions below 1.5 ppm.[89] Based on these analyses, the cost of achieving a 1.5 ppm permit limit would be an additional $179,600 per year (above what it would cost to achieve a 2.0 ppm limit), and the additional reduction in CO emissions would be approximately 11 tons per year, making an incremental cost-effectiveness value of over $16,000 per ton of additional CO reduction.[90] Moreover, the total cost of achieving a 1.5 ppm CO limit (as opposed to the incremental costs of going from 2.0 ppm to 1.5 ppm) would be over $840,000 per year, and the total emission reductions of a 1.5 ppm limit would be 186 tons per year, making a total (or "average") cost effectiveness value of over $4,500.[91] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.5 ppm CO permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 1.5 ppm limit would be far more expensive, on a per-ton basis, than what other similar facilities are required to achieve. The Air District has not adopted its own cost-effectiveness guidelines for CO,[92] but a review of other districts in California found none that consider additional CO controls appropriate as BACT where the total (average) cost-effectiveness will be greater than $400 per ton, or where the incremental cost-effectiveness will be over $1,150 per ton.[93] Moreover, a review of recent CO BACT determinations in EPA's RACT/BACT/LAER Clearinghouse did not reveal any permits that had imposed CO controls at a cost-per-ton in the range that would be required here. The permits in the Clearinghouse going

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

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

[91] *See* Spreadsheet, Average/Total Cost Effectiveness Analysis for CO Control from 2 to 1.5 ppmv, prepared by Barbara Mcbride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.

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

[93] South Coast Air Quality Management District, *Best Available Control Technology Guidelines*, August 17, 2000, revised July 14, 2006, at 29; available at: http://www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf.

back through 2005 that included cost-effectiveness information showed a limit of 1.8 ppm being imposed based upon an average cost-effectiveness of $1,750 per ton of CO;[94] a limit of 3.5 ppm based upon an average cost-effectiveness of $2,736 per ton and an incremental cost-effectiveness of $5,472 per ton;[95] and a limit of 2.0 ppm an average cost-effectiveness of $1,161 per ton of CO.[96] Both the average and incremental cost-effectiveness values of imposing a 1.5 ppm limit for the Russell City facility would be substantially higher than what was required for any of these other similar facilities.

Because both the average and incremental costs per ton of CO that would be reduced by imposition of a CO limit below 2.0 ppmvd are significantly higher than the costs that have been or would be required at other similar facilities, the Air District is proposing not to require that level of control as BACT. Although it appears that an additional reduction below 2.0 ppm may well be feasible based on permits that have been issued to other facilities, the Air District would eliminate it as a BACT requirement in Step 4 of the Top-Down BACT analysis because it is not "achievable" for purposes of a BACT analysis taking into account cost/economic impacts.

Finally, the Air District received a comment claiming that different types of oxidation catalysts available for controlling CO will have different impacts on HAP and POC emissions, citing a 2002 EPA memorandum regarding HAP emissions from combustion turbines ("Roy Memorandum").[97] This comment claimed that the District should evaluate the differences between different types of oxidation catalysts in its CO BACT analysis. The Air District disagrees that there is evidence that different kinds of oxidation catalysts will have different impacts on HAP and POC emissions. The memorandum the comment relies on does not state that different oxidation catalysts will have different impacts on HAP and POC emissions. To the contrary, the memorandum (including its attachment) identify several specific types of catalysts, such as platinum, palladium, rhodium, and metal oxides, and discusses them all generally simply as "oxidation catalysts". (*See* Roy Memorandum at p. 6.) Moreover, the memorandum does not claim that SCONOx has any different impact on HAP or POC emissions than any other type of oxidation catalyst. To the contrary, it explicitly states that the two technologies are "comparable" in this regard, and in fact bases its evaluation of all oxidation catalysts generally on an evaluation of SCONOx. (*See id* at p. 1.) The only difference the memorandum points out between the two technologies is that SCONOx uses a chemically modified catalyst so that the catalyst also removes NOx. (*See id.*) For the Russell City Energy Center, the District is proposing to approve SCR for NOx control, and so the NOx-removal aspect of SCONOx does not provide any improvement over the combination of SCR for NOx control and an oxidation catalyst for CO control. The Air District is unaware of any studies on different types of

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[94] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008.

[95] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005.

[96] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005.

[97] The memorandum cited is available at www.epa.gov/ttn/atw/combust/turbine/cttech8.pdf.

oxidation catalysts and associated abatement efficiencies for VOCs and HAPs, and has found nothing in this comment or elsewhere that warrants revising the BACT analysis for CO.

VI. PARTICULATE MATTER ISSUES

The Air District has made several revisions to its permit analysis with respect to particulate matter issues. The Air District's further analysis on these issues is discussed in this section.

A. Additional BACT Analysis Regarding Lowering Particulate Matter Emissions

Since the Air District initially issued the Draft Federal PSD permit, the District has explored whether particulate emissions limits for the turbines and heat recovery boilers could be further reduced in order to ensure that the facility will not cause exceedances of the National Ambient Air Quality Standards for particulate matter. Based on this further review, the Air District is proposing a revised limit on particulate matter emissions (for both PM_{10} and $PM_{2.5}$) from each gas turbine and heat recovery boiler train of 7.5 lb/hr or 0.0036 lb/MMBTU natural gas fired (with or without duct firing). This emissions limit would include all filterable and condensable particulate emissions (*i.e.*, "front" and "back" half, respectively).

The Air District has concluded that a lower limit of 7.5 lb/hr would be achievable by this equipment based on a review of additional source testing data from a number of similar combined-cycle facilities. These 73 source tests showed average particulate emissions of 4.58 lb/hr, with a high of 10.65 lb/hr.[98] The Air District believes that some of the higher test results may be attributed to anomalies in the testing and analytical methods, the influence of which may be mitigated by application of more rigorous quality assurance/quality control ("QA/QC") by the testing contractor or analytical laboratory. The Air District has therefore concluded that it would not be appropriate to establish a compliance margin that would accommodate these high test results. Instead, the Air District is discounting the highest 5% of the test results (4 of the 73), and proposing a permit limit based on the remaining 95%. This approach yields a proposed permit limit of 7.5 lb/hr. The Air District has also reviewed available permits for other similar facilities and has not found any lower permit limits. The Air District is therefore proposing a revised PM_{10}/$PM_{2.5}$ limit for each gas turbine/heat recovery boiler train of 7.5 lb/hr, or 0.00335 lb/MMBTU of natural gas fired, as the BACT limit for the sources. The Air District is also revising its proposed conditions for the daily and annual particulate matter limits accordingly.

The Air District also conducted a similar review of the BACT limits for particulate matter emissions from the cooling tower. As noted in the initial Statement of Basis, the cooling tower can contribute to particulate matter emissions through solids dissolved in the water used in the cooling system, which can be emitted in the water vapor exhausted through the cooling tower. The Air District concluded that imposing a direct numerical limitation on emissions of PM from the cooling tower was infeasible, and instead proposed to limit the Total Dissolved Solids

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[98] Each source test result represents the average of multiple test runs (3 in most cases) performed on the same unit. For a summary of the source test results, see spreadsheet, "Summary of Filterable PM_{10}", submitted by B. McBride (Director, Environment, Health and Safety, Calpine Corporation) to B. Bateman (Director, Engineering/Toxic Evaluation, Air District), W. Lee (Senior AQ Engineer, Engineering/Permit Evaluation, Air District) and B. Nishimura (Supervising AQ Engineer, Engineering/Permit Evaluation, Air District), by email dated June 10, 2009.

("TDS") in the cooling water to 8,000 parts per million by weight (along with a requirement to equip the cooling tower with high-efficiency drift eliminators guaranteed to achieve less than 0.0005 percent drift). (*See* Statement of Basis at p. 78 & proposed Condition No. 44.)

The Air District has conducted a further analysis of TDS data from the source of the proposed facility's cooling water, the City of Hayward's Waste Water Treatment Plant, which is adjacent to the proposed facility. Based on this analysis, the Air District has concluded that the facility should be able to keep the TDS of the cooling water at 6200 ppm or below. The Air District is therefore revising the proposed BACT limit for TDS from 8000 ppm to 6200 ppm.

B. Recent Regulatory Developments Regarding $PM_{2.5}$

There have also been several regulatory developments regarding particulate matter since the Air District issued the initial Draft PSD Permit and Statement of Basis. First, EPA has decided to reconsider (and apparently to repeal) its recently-adopted provision in 40 C.F.R. 52.21(i)(1)(xi) that directs PSD permitting agencies to use the so-called PM_{10} "surrogate" approach in addressing $PM_{2.5}$ compliance issues. EPA also stayed the effectiveness of Section 52.21(i)(1)(xi) while the reconsideration proceedings are underway. These developments make clear that EPA is changing its guidance on how to address $PM_{2.5}$ issues for PSD permitting purposes, and in response the Air District has concluded that $PM_{2.5}$ issues must be addressed directly and not through reliance on the surrogate policy.[99] This development means that the PSD permit analysis must (i) demonstrate that the facility will use Best Available Control Technology to control $PM_{2.5}$ emissions; and (ii) conduct an Air Quality Impact Analysis showing that the facility will not contribute to an exceedance of the $PM_{2.5}$ NAAQS (either the 24-hour standard or the annual standard).

Second, the outgoing EPA administrator signed a Federal Register notice on December 18, 2008, that would have the effect of designating the Bay Area as non-attainment of the National Ambient Air Quality Standard for $PM_{2.5}$ (24-hour average).[100] Although the document was signed by the outgoing EPA Administrator, the incoming administration has thus far declined to go ahead and actually publish it in the Federal Register. For that reason, the non-attainment designation has not become effective, and will not become effective for 90 days after Federal Register publication. This situation leaves the Bay Area in a sort of regulatory limbo on this issue, as the region is technically still unclassified for $PM_{2.5}$ (24-hour average) but is subject to an impending non-attainment designation that could become effective in the near future. This

[99] The granting of reconsideration and the issuance of the stay were made by letter from the EPA Administrator dated April 24, 2009, and in a subsequent Federal Register Notice dated June 1, 2009 (74 Fed. Reg. 26098). Before Section 52.21(i)(1)(xi) was adopted, the *status quo* was to follow published EPA policy guidance mandating the use of the surrogate approach, and there may be an argument that with Section 52.21(i)(1)(xi) stayed the situation should revert to that *status quo*. But the Administrator made clear in her letter that EPA considers that policy "no longer substantially justified . . . ," and will propose to repeal it. The Air District takes this as guidance rejecting the use of the surrogate policy, which would supersede any earlier guidance to the contrary.

[100] The re-designation as non-attainment was for the 24-hour standard only; the Bay Area would remain unclassifiable for the annual standard.

situation impacts the proposed Russell City permit because if the Bay Area remains unclassified, it will continue to be subject to PSD permitting requirements for $PM_{2.5}$ (24-hour average), but if the Bay Area becomes non-attainment the facility will be subject to Non-Attainment NSR permitting requirements for $PM_{2.5}$ (24-hour average).

The Air District is addressing this rapidly-evolving situation by proposing two separate alternative routes for public review and comment: First, the Air District is proposing that in the event that the Bay Area remains unclassified for $PM_{2.5}$ (24-hour average), it will issue a Federal PSD Permit addressing $PM_{2.5}$ for both the 24-hour and annual standards. Second, the Air District is proposing that in the event the Bay Area is designated non-attainment during the remainder of this proceeding, the Air District will issue a Federal PSD Permit addressing $PM_{2.5}$ for the annual standard only, and will leave NSR applicability issues regarding the 24-hour standard subject to 40 C.F.R. Part 51, Appendix S, which contains the regulatory requirements for non-attainment areas in the interim between the date of designation as non-attainment and the time that the state can adopt its own SIP-approved Non-Attainment NSR permit requirements. These two alternative approaches are set forth below. The Air District seeks input and comment from the public on both alternatives, and proposes to proceed with the appropriate alternative depending on how regulatory developments unfold during the remainder of this permit proceeding.

1. Continued "Unclassifiable" Status For $PM_{2.5}$ (24-hour)

If the District continues to be designated unclassifiable for $PM_{2.5}$ (24-hour average), the proposed Russell City Energy Center will be subject to two additional general areas of regulatory requirements: BACT and the Air Quality Impacts Analysis.

The first main area of additional analysis is that the facility will have to use BACT to control $PM_{2.5}$ emissions in accordance with 40 C.F.R. Section 52.21(j). With respect to the combustion turbines and heat recovery boilers, the BACT analysis for $PM_{2.5}$ is the same as for PM_{10}. Particulate emissions from natural gas combustion are less than one micron in diameter, so by definition it is both $PM_{2.5}$ and PM_{10}.[101] $PM_{2.5}$ and PM_{10} are therefore one and the same for natural gas combustion, and so the District is therefore proposing to use the same BACT analysis for $PM_{2.5}$ as it is using for PM_{10}. The Air District incorporates by reference the analysis set forth in the initial Statement of Basis PM_{10} as applicable for $PM_{2.5}$ as well. The Air District is also adding proposed conditions that will be applicable for $PM_{2.5}$ for these sources, as well as monitoring and recordkeeping requirements to ensure compliance. For the diesel firepump engine, the BACT analysis concluding that BACT requires the use of ultra-low-sulfur diesel fuel and an EPA-certified engine is the same for $PM_{2.5}$ as well. This BACT requirement, which was described in the initial Statement of Basis on pp. 51-56, was applicable to all PSD pollutants covered in the initial Statement of Basis and is applicable to $PM_{2.5}$ as well. Use of ultra-low-sulfur diesel fuel and an EPA-certified engine will provide the maximum level of $PM_{2.5}$ emissions control that is achievable at this time. For the cooling tower, the BACT control requirements the District has proposed for PM_{10} – keeping Total Dissolved Solids (TDS) in the

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

cooling water to the minimum feasible level and using high-efficiency drift eliminators[102] – are also the only effective mechanisms to control $PM_{2.5}$ emissions, and will ensure that $PM_{2.5}$ emissions are minimized to the maximum achievable extent consistent with the BACT requirements. The Air District solicits comment from interested members of the public on these $PM_{2.5}$ BACT issues.

Recent $PM_{2.5}$ regulations also require facilities to use BACT control technology to limit emissions of NOx and SO_2 as precursors to $PM_{2.5}$ formation, to the extent that the facility will emit those precursors in significant amounts.[103] NOx and SO_2 emissions are considered to be "significant" if they exceed 40 tons per year. (*See* 73 Fed. Reg. 28321, 28333 (May 16, 2008); 40 C.F.R. § 52.21(b)(23)(i).) The proposed Russell City facility will emit less than 40 tons per year of SO_2, but more than 40 tons per year of NOx. (*See* Statement of Basis at p. 14.) The facility must therefore use BACT to control NOx as a $PM_{2.5}$ precursor. The Air District has already evaluated NOx emissions and has proposed BACT limits for NOx in connection with the PSD requirements for NO_2, however. (*See* Statement of Basis at pp. 21-29.) No additional analysis or permit conditions are required to ensure compliance with this requirement.

The second main area of additional analysis is that the facility has to conduct an Air Quality Impact Analysis as required by 40 C.F.R. Sections 52.21(k)-(o). The facility has to undertake a Source Impact Analysis to show that it will not cause or contribute to an exceedance of the National Ambient Air Quality Standards or PSD increment for $PM_{2.5}$ as required by 40 C.F.R. Section 52.21(k); and has to conduct an additional impact analysis as required by 40 C.F.R. Section 52.21(o). These analyses have been conducted, and demonstrate that the proposed facility's $PM_{2.5}$ emissions (i) will not cause or contribute to an exceedance of any $PM_{2.5}$ NAAQS or increment; (ii) will not cause any significant impairment of visibility; and (iii) will not have any significant adverse impacts on soils and vegetation. These issues are discussed in detail in Section XI below, which addresses Air Quality Impacts Analysis issues. As explained in Section XI, the facility satisfies the Air Quality Impacts Analysis requirement in 40 C.F.R. Sections 52.21(k)-(o) with respect to $PM_{2.5}$ emissions.

2. Designation as "Non-Attainment" For $PM_{2.5}$ (24-hour)

In the event that the Bay Area is designated as non-attainment for the $PM_{2.5}$ 24-hour average standard, the Air District proposes to interpret this "split" designation (*i.e.*, non-attainment for the 24-hour standard and unclassifiable for the annual standard) as follows. Facilities that are major facilities for purposes of $PM_{2.5}$ under the PSD regulations will continue to be subject to PSD permitting, but only for the annual standard. That is, they will have to apply BACT for $PM_{2.5}$ and conduct an Air Quality Impact Analysis to show no violation of the annual standard. For facilities that are also major facilities for purposes of $PM_{2.5}$ under EPA's Non-Attainment NSR permitting requirements, these facilities will also be required to obtain Non-Attainment NSR permits for $PM_{2.5}$ in accordance EPA's Clean Air Implementation Rule, which applies to

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[102] *See* Statement of Basis at pp. 50-51.

[103] The regulations also provide for states to require BACT for VOC and ammonia emissions if they determine to EPA's satisfaction that such emissions are a significant precursor to $PM_{2.5}$ formation, but no such determination has been made for the Bay Area.

sources in non-attainment areas while a state is developing its own Non-Attainment NSR requirements for $PM_{2.5}$. The Clean Air Implementation Rule is contained in Appendix S of 40 C.F.R. Part 51 ("Appendix S"). The Air District solicits comment on whether this is the correct approach, or whether Non-Attainment NSR permitting under Appendix S supersedes PSD permitting such that facilities would be subject to Appendix S permitting only for $PM_{2.5}$, as has been suggested from some quarters.

Based on this proposed approach for addressing "split" attainment designations, the Air District has analyzed the applicability of Appendix S in the event that the Bay Area's $PM_{2.5}$ (24-hour) re-designation becomes effective during this permitting proceeding. Here, the facility would be exempt from Appendix S because it will emit less than 100 tons per year of $PM_{2.5}$. (*See* 40 C.F.R. Appendix S, ¶ II.A.4(i)(a) (establishing 100 tpy threshold for regulation of Major Stationary Sources).[104]) There would be no additional Clean Air Act regulatory requirements applicable beyond the PSD regulations, and no additional federal permit required beyond the PSD Permit.[105]

With respect to PSD issues in the event the $PM_{2.5}$ (24-hour average) non-attainment designation becomes effective during the permit proceeding, the facility will remain subject to PSD permitting for the annual standard. The PSD analysis for this element of the permit will be the same as under the first scenario outlined above where the non-attainment designation does not become effective. The facility satisfies the $PM_{2.5}$ BACT and air quality impact analysis requirements for the annual standard as discussed above.

The District solicits public comment on all of these issues, including the applicability of $PM_{2.5}$ requirements, the $PM_{2.5}$ BACT analysis (as well as revised PM_{10} emissions limits), the determinations that the facility will not contribute to exceedances of the 24-hour or annual $PM_{2.5}$ NAAQS, the applicability of Appendix S in the event the Bay Area's redesignation becomes effective, and any other relevant issues.

C. <u>Ammonia Slip/Secondary Particulate Matter Formation</u>

The Air District also received comments questioning its analysis in the Statement of Basis that ammonia slip from the facility would not contribute to the formation of secondary particulate matter. The comments suggested that the memorandum the District cited in support of its conclusion that the Bay Area is nitric-acid limited was specific only to the San Jose/Livermore area and cannot be used to support a determination for the Hayward area. The comments further claimed that the District should undertake a BACT analysis for ammonia slip based upon the

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[104] $PM_{2.5}$ is, by definition, a subset of PM_{10}. The fact that the facility will emit less than 100 tons per year of PM_{10} therefore establishes that it will emit less than 100 tons per year of $PM_{2.5}$. In addition, the facility will not emit more than 100 tons per year of $PM_{2.5}$ precursors, as defined in Appendix S ¶ II.A.31(iii). (*See* Statement of Basis, p. 14 Table 5.)

[105] In addition, it is worth noting that any Appendix S requirements would be applicable through a Non-Attainment NSR permit, not through the PSD Permit. There may be reasons to address both types of requirements in an integrated permit proceeding, but technically they are separate permitting programs applicable under different sections of the Clean Air Act.

potential for secondary PM formation. The comments also questioned the District's statement earlier in the permitting process that the potential impacts of ammonia slip emissions on the formation of secondary particulate matter within the boundaries of the San Joaquin Valley Air Pollution Control District are not known.

The Air District would like to take this opportunity to clarify its analysis in light of these comments. Although the comments are correct that the District's study finding nitric-acid limited conditions looked only at the San Jose and Livermore areas, which are south and east of the proposed project location, respectively, there is no indication that the same atmospheric conditions do not exist in the Hayward area as well. They are part of the same general airshed as Hayward, and the Air District is not aware of any data or other information to suggest that conditions may be materially different. The Air District therefore continues to believe that the evidence before it supports the conclusion that the air in the region of the proposed facility is nitric-acid limited, and that additional ammonia emissions in the form of ammonia slip are not likely to have any significant contribution to secondary particulate matter formation. If members of the public have data or information that the location of the proposed facility is in fact not nitric-acid limited, the Air District asks that the public submit it during the additional comment period so the District can consider it.

Moreover, secondary PM formation is a complex process that is not well understood at the present time. As EPA recently noted in its rulemaking on secondary particulate matter precursors, "Ammonia emission inventories are presently very uncertain in most areas, complicating the task of assessing potential impacts of ammonia emission reductions. In addition, data necessary to understand the atmospheric composition and balance of ammonia and nitric acid in an area are not widely available, making it difficult to predict the results of potential ammonia emission reductions."[106] Given this situation, the suggestion that ammonia slip from the facility may cause significant secondary Particulate Matter formation is speculative at most. EPA has made clear that it Federal PSD Permitting decisions should not be made based on potential impacts that are merely speculative in nature.[107] The Air District notes that the commenters' assertions about the areas in which the District's study could be made more comprehensive only highlight the uncertainties surrounding the issue of secondary Particulate Matter formation and the speculative nature of their claims that ammonia slip will cause additional Particulate Matter impacts.

Furthermore, EPA has found countervailing considerations that would counsel against unnecessarily restricting ammonia slip emissions, in the form of neutralizing harmful acids in the atmosphere. As EPA explained in its recent rulemaking, "Ammonia serves an important role in neutralizing acids in clouds, precipitation, and particles. In particular, ammonia neutralizes sulfuric acid and nitric acid, the two key contributors to acid deposition (acid rain)." EPA cited this trade-off between the potential benefits and drawbacks of ammonia restrictions, as well as

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[106] Final Rule, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$), 73 Fed. Reg. 28321, 28330 (May 16, 2008) (hereinafter, "$PM_{2.5}$ Implementation Rule").

[107] *See In re Three Mountain Power*, 10 E.A.D. 39, 57-58 (EAB 2001); *see also In re Sutter Power Plant*, 8 E.A.D. 680, 693-94 and n. 13 (EAB 1999).

the uncertainties surrounding the formation of secondary Particulate Matter from ammonia emissions, in adopting a presumption that ammonia should not be regulated as a precursor to Particulate Matter formation.[108] The Air District is mindful of these issues and declines to depart from EPA's considered approach, especially where the evidence that is available indicates that ammonia slip will not be a significant contributor to Particulate Matter formation in this case.

For these reasons, the Air District concludes that the Federal PSD BACT requirement does not require an analysis of ammonia slip emissions, as would be required if ammonia slip was demonstrated to be a precursor to Particulate Matter formation and that it would be emitted in significant amounts. If members of the public have additional information that may be relevant to these issues, the Air District invites the public to submit it during the additional comment period so the Air District can consider it further.

[108] *See* $PM_{2.5}$ Implementation Rule, *supra* note 106, at p. 28330.

VII. STARTUP AND SHUTDOWN ISSUES

The Air District received a number of comments on the proposed BACT startup and shutdown emission limits and District's technical analysis supporting them. In response to these comments, the Air District has further reviewed the proposed startup limits and is now proposing to strengthen them in several areas. The Air District addresses these and other startup-related issues in this section.

A. Applicability of BACT Requirement to Startups And Shutdowns

The District received one comment that claimed to disagree with the District's statement that the stringent BACT limits proposed for normal operations would not be achievable during startups and shutdowns. The comment claimed that the permit needs to include BACT limits for all operating modes, and cannot exclude startups and shutdowns from the BACT requirement. In this context, the comment cited the Environmental Appeals Board's decisions in the *Indeck-Niles Energy Center* case (in which the EAB observed that the petitioner had failed to raise the issue of whether the permit should have imposed short-term BACT emission limits for startup and shutdown emissions) and the *Tallmadge Generating Station* case (in which the EAB held that that PSD permits need to include BACT limits for startup and shutdown events). To clarify the record on this issue, the Air District agrees that BACT is applicable to and required for startup and shutdown operations. The District included BACT limits for startups and shutdowns in its initial proposal, and is now proposing even more stringent BACT limits for startups and shutdowns in this revised proposal. The District's analysis and permit limits are consistent with the cited EAB precedents and other authorities regarding BACT. The commenter appears to have misunderstood the District's point that the specific BACT limits imposed for normal operations are not achievable during startups and shutdowns. That point does not mean that BACT does not apply during startups and shutdowns, it simply means that different limits specific to those operating periods (and achievable during those periods) must be imposed.[109] The Air District invites further public comment on this issue in light of this clarification. If any member of the public continues to believe that the Air District is not proposing to impose permit conditions that would limit emissions during startups and shutdowns, the public is invited to submit comments explaining the basis for such a belief.

B. Proposed BACT Limits For Startups

The District also received a number of comments on the permit limits it proposed for startups and shutdowns. Upon further review, the Air District agrees with many of these comments, and in response has reconsidered its earlier proposal and is now proposing to reduce the startup limits in several areas as outlined below.

[109] *See In re Indeck-Niles Energy Center*, PSD Appeal No. 04-01, slip op. at 14-15 (EAB Sep. 30, 2004).

1. Stringency of Startup Emissions Limits

Several commenters claimed that the Air District should impose more stringent emissions limits for startups. In support, these commenters cited several facilities that they claimed establish that lower startup limits would be achievable for this facility. In particular, the commenters pointed to the Palomar Energy Center in Escondido, CA; the Lake Side Power Plant in Vineyard, UT; and the Caithness Long Island Energy Center in Brookhaven, NY, as facilities that demonstrate that startup lower limits would be achievable as BACT here. The Air District evaluated data from the first of these, Palomar, in the initial Statement of Basis (*see* Statement of Basis at pp. 41-42), but the comments claimed that additional data from the facility is available and that the Air District should obtain and analyze all available data. Some commenters stated that the Air District should require the specific technologies used at these facilities as BACT; while others stated that the Air District should establish a BACT emissions limit reflecting the same level of startup emissions reductions as achieved at these facilities, if it does not impose a requirement specifying the particular type of equipment to use.

The Air District agrees with these comments that based on all of the available information, including the examples from these three facilities, the facility should be able to achieve lower BACT startup emissions limits than the Air District initially proposed in several areas. For NO_2 emissions, the Air District has concluded that the BACT limit for hot startups should be lowered from 125 lbs. to 95 lbs. based on further review of the emissions performance achieved by other facilities, including the Palomar Energy Center. For warm and cold startups, the Air District continues to believe that the NO_2 emissions limits it initially proposed are appropriate because the additional information it has reviewed supports these limits as the lowest that can reasonably be achieved over time. For CO emissions, the Air District has concluded that the emissions limits should be reduced from 5028 lbs. to 2514 lbs. for cold startups and from 2514 pounds to 891 pounds for hot startups. For warm startups, the Air District continues to believe that the CO limit of 2514 points initially proposed is the appropriate BACT limit. Table 3 below provides a summary comparison of the startup emissions limits the District initially proposed and the revised limits the District is now proposing.

Table 3: Summary of Initial and Revised Proposed Startup Emissions Limits

	NO_2 Emissions Limits (lbs/startup)		CO Emissions Limits (lbs/startup)	
	Initial Proposal	Revised Proposal	Initial Proposal	Revised Proposal
Hot Startups	125	95	2514	891
Warm Startups	125	125	2514	2514
Cold Startups	480	480	5028	2514

The Air District's further evaluation of the appropriate BACT startup limits, including its assessment of the three comparable facilities cited in the comments received so far, is set forth in detail in the following paragraphs.

- ***Palomar Energy Center, Escondido, CA***

With respect to the Palomar facility, the Air District obtained additional emissions data that has been reported to the San Diego Air Pollution Control District (SDAPCD). This data included all NOx emissions data for the facility from October of 2006 through the end of 2007, and covers approximately 36 startup events involving the two turbines at the facility.[110] This is substantially more data than the Air District had from this facility when it initially considered the proposed startup limits in the initial Statement of Basis, although it is still somewhat of a preliminary picture of what the facility will be able to achieve over the long term given that it represents only a little over a year's worth of operation. Nevertheless, the Air District believes that it can use the data for what it is – an early indication of what startup NO_2 emissions this facility is likely to be able to achieve.[111]

The Air District has therefore analyzed all of this data, in conjunction with the startup data from other facilities it reviewed in its original analysis for the proposed permit, to refine its BACT analysis for startups. The Air District's analysis was based on taking the raw, minute-by-minute CEM data from the facility and estimating when startups began and ended based on changes in O_2 concentrations. The Air District notes that the emission rates it arrived at through these calculations are somewhat lower than the emissions rates calculated by the SDAPCD for the four startups where SDAPCD calculations are available.[112] The Air District therefore concludes that its method is a conservative assessment of the actual emissions performance achieved during these events. The Air District also notes that it considered data only from after October 13, 2006, for turbine 1 and after October 12, 2006, for turbine 2, the dates on which the facility began to implement the full complement of efforts it has made to reduce startup emissions under

[110] The Air District sought additional data since the end of 2007, but the facility has not reported any to the SDAPCD. The Air District also contacted the Palomar facility directly and requested review of additional data, but the facility declined and the Air District had no way to compel release of the data. (Telephone conversation between Alexander G. Crockett, Esq., BAAQMD, and Taylor O. Miller, Esq., Sempra Energy, 4/15/09.) In addition, the applicable permit limits for Palomar are of little help in evaluating the appropriate BACT permit conditions here, as they are much higher than those proposed for Russell City and the Air District does not consider them to represent BACT limits.

[111] Note that the startup limits in the permit for the Palomar facility are far higher than anything the Air District has considered for Russell City: 400 lbs/hr NO_x and 2,000 lbs/hr CO (note that these limits are *hourly* limits, meaning that total emissions for an entire startup can be several times these hourly rates). (*See* Startup Authorization, SDG&E, 2300 Harveson Place, Escondido, CA 92029, San Diego County Air Pollution Control District, App. No. 984461, PO No. 976846, April 30, 2008, at Conditions No. 16-17.)

[112] The four startup events where SDAPCD calculations are available are the following:

Date	Turbine	SDAPCD Calculation	BAAQMD Calculation
12/10/06	1	26 pounds	22 pounds
10/22/07	1	285 pounds	225 pounds
12/23/06	2	115 pounds	111 pounds
10/22/07	2	437 pounds	375 pounds

In the following analysis, where data points are available from both the SDAPCD and BAAQMD calculations, both are given for the sake of completeness.

a variance from the SDAPCD Hearing Board. The Air District excluded data from these dates and before because the commenters who urged the Air District to consider the Palomar data asserted that it is the period after implementation of these efforts that evidences the best achievable startup emissions performance. Since the excluded data consist of, for the most part, data showing high emissions (for example, a cold startup event at turbine 1 on October 11, 2006, that produced 735 pounds of NO_2 emissions), the District's approach is, again, conservative.

Once the Air District collected and refined the data from Palomar, it broke the data out into cold, warm, and hot startups in order to compare it with the proposed Russell City limits.[113] (The Air District's summary of the Palomar data points is set forth in Appendix A.) Looking first at cold startups, the available data suggests that the Palomar facility is achieving cold startup emissions at levels very similar to the facilities on which the Air District based its initial proposed Russell City startup limits. The average NO_2 emissions for cold startups (defined as the turbine having been down for over 48 hours) were 182.8 pounds, which is very similar to the cold startup averages that the Air District reviewed for the Delta Energy Center and Metcalf Energy Center in the Statement of Basis, which were 193 pounds and 185 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). The highest NO_2 emissions during a cold startup at Palomar, on October 22, 2007, was 375 pounds according to the District's calculations or 437 pounds according to the SDAPCD's calculations, which again is similar to Delta and Metcalf, for which the highest cold startups were at 281 and 335 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). Based on this review, it appears that Palomar is performing at or near the level of the other similar facilities that the Air District considered in the Statement of Basis, but certainly not any better than that. The Air District concludes from this comparison that the Palomar data serve to confirm its earlier assessment of the appropriate cold startup limits for Russell City, and certainly do not suggest that the initial analysis was inaccurate.

The Air District did observe that the Palomar data showed a maximum startup emissions event of 375 or 437 pounds (depending on which calculation is used), which is somewhat below the proposed Russell City cold startup limit of 480 pounds, but the Air District does not consider this level of compliance margin – which is 9%-22% of the permit limit, depending on whose calculation is used – to be unreasonable for several reasons. First, the data from Palomar includes only five available data points for cold starts, which does not generate a great deal of statistical confidence that the maximum seen in this data set is representative of the maximum that can be expected over the entire life of the facility. Moreover, the wide variability in the data that is available highlights the variability in individual startups, underscoring the need to provide a sufficient compliance margin to allow the facility to be able to comply during all reasonably foreseeable startup scenarios. For both of these reasons, the Air District has concluded that a cold startup limit of 480 pounds of NO_2 is a reasonable BACT limit that is consistent with the startup emissions performance seen at the Palomar facility.

The Air District next reviewed the warm startup NO_2 emissions data from Palomar. The available Palomar data show NO_2 emissions from warm startups ranging as high as 111 pounds,

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[113] Cold startups are startups when the turbine has been off-line for more than 48 hours; warm startups are when the turbine has been off-line for between 8 and 48 hours; and hot startups are when the turbine has been offline for less than 8 hours.

or 115 pounds according to SDAPCD's calculations (on December 23, 2006). This is just 14 pounds (or 10 pounds according to SDAPCD) below the proposed warm start limit of 125 pounds, or 11% (8%) of the proposed limit. The Air District concludes from this evidence that the proposed limit is at least as stringent as could consistently be expected at Palomar. It is statistically unlikely that the highest-emission startup event over the lifetime of the facility would occur during the first 14 months of available data, and it is therefore reasonable to anticipate that emissions could be even more than 111 pounds (or 114 pounds) during certain warm startups. A compliance margin of an additional 11% (or 8%) over the maximum observed over the first 14 months of data at Palomar is not unreasonable, and is appropriate to accommodate the variability in emissions among startup events over time. The Air District therefore finds no basis in the Palomar warm startup data to impose a more stringent NO_2 limit than the 125 pounds-per-startup limit it initially proposed.

Third, the Air District reviewed the hot startup NO_2 emissions data from Palomar. The data the Air District reviewed showed a startup designated as "regular" startup with NOx emissions of 145 pounds (May 1, 2007). "Regular" startups presumably indicate hot starts, as that is the most normal and frequent type of startup at the facility,[114] but the Air District finds it questionable as to whether this was actually a hot startup (*i.e.*, occurred when the turbine was down for less than 8 hours). Taking the data without this apparent outlier, the Palomar startup data show average NOx emissions of 30.3 pounds and a maximum startup event of 75 pounds (November 27, 2006). Looking at the average startup emissions, it appears that Palomar is actually experiencing *higher* average hot startup emissions than the Delta Energy Center on which the Air District based its initial startup limit evaluation. The average hot startup NO_2 emissions for the years 2005 through 2008 at Delta were 25, 26.6, 27.6, and 29.8 pounds respectively, which are all better than the 30.3 pound average at Palomar (and much better than the average of 38.5 pounds if the May 1, 2007 outlier startup is included). Looking at the highest reported startup events, the data from Palomar show a high similar to the highest high at Delta, although a little lower. The highest hot startup seen at Delta was 82.2 lbs, which is slightly higher than the 75 pound startup event at Palomar on November 27, 2006 (although still much better than the 145-pound outlier event of May 1, 2007). The Air District has therefore concluded that for hot startups that the Palomar facility is not achieving an overall startup emissions performance any better than the other comparable facilities the Air District evaluated in establishing the proposed BACT limits. In further considering all of this data, however, the Air District has concluded that a somewhat more stringent compliance margin would probably be achievable here for hot startups. At the 125 pounds hot-start limit initially proposed, the compliance margin would be 43 pounds more than the highest data point found at Delta and 50 pounds more than the highest data point from Palomar. The Air District is therefore proposing a lower NO_2 limit for hot starts in the revised draft permit of 95 pounds per startup. This lower limit would bring the permit limit more in line with the high-emissions startups that have been seen at other similar facilities, while still providing an appropriate margin of compliance to take into account the fact that startups are by their nature highly variable and the highest startup emissions seen in the data collected to date may not necessarily reflect the highest emissions that would reasonably be expected under all circumstances over the life of the facility.

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[114] The Palomar facility most commonly operates during the day and shuts down overnight, so its most common startups are after less than 8 hours of down-time.

In summary, the Air District agrees with the commenters that the additional NO_2 startup data from Palomar shed more light on what level of startup emissions should be achievable at Russell City. The Air District reviewed the additional data and found that Palomar has so far been achieving emissions rates very similar to the facilities on which the Air District based its proposed limits. Based on its review of this data, the Air District has concluded that Palomar confirms the Air District's initial assessment in the Statement of Basis with respect to cold and warm startups, but provides evidence with respect to hot startups that the emissions limit can be reduced from the proposed 125 pounds to 95 pounds per startup. With this revised hot startup limit, the Russell City permit limits align very closely with the startup emissions seen at Palomar based on the available data, as summarized in Table 4 below:

Table 4: Comparison of Palomar Startup NOx Emissions Data to Proposed Russell City NOx Startup Limits

	Palomar 14-Month Maximum*	**Russell City Permit Limit**
Hot Startup	75 pounds	95 pounds
Warm Startup	111/115 pounds**	125 pounds
Cold Startup	375/437 pounds**	480 pounds

*excluding startups that occurred before implementation of startup emissions reduction measures.
**BAAQMD/SDAPCD calculations, respectively

- ***Lake Side Power Plant & Caithness Long Island Energy Center***

The Air District also reviewed the Lake Side Power Plant and Caithness Long Island Energy Center, the other two facilities that the commenters cited. The commenters discussed these two facilities primarily in the context of using an emerging startup technology – the "Fast-Start" once-through steam boiler design – in order to reduce startup emissions. As explained in greater detail in the startup technology section below, the Air District investigated these facilities further and found that they do not use Fast-Start technology, although they do utilize an auxiliary boiler that has a startup emissions benefit. Nevertheless, they are similar combined-cycle facilities and the Air District evaluated whether they are achieving better startup performance.

The only way to compare the Lake Side and Caithness facilities is based on their startup permit limits, as there is no published data from either facility because they are only just coming online. The Caithness facility has not yet been built, while the Lake Side facility has been operating only since December of 2008, as some commenters pointed out, and the Air District is not aware of any actual operating data that is available for it. Without actual operating data available for review, the Air District compared the permit limits for those facilities to see whether they suggest that lower permit limits might be appropriate for Russell City.

First, for Lake Side, the facility's permit has *no* limits whatsoever on emissions during startups.[115] The Air District does not believe that it would be appropriate to issue a permit for

[115] Utah DEQ Approval Order DAQE-AN3031001-05 (Lake Side Power Plant), Conditions 9 & 12 (available at www.airquality.utah.gov/Permits/DOCS/AN3031001-05.pdf.) The permit does

the Russell City Energy Center without limits on startup emissions, as discussed above. But to the extent that commenters contend that the Air District should look to Lake Side as a comparable facility, there are no startup limits to compare.

For Caithness, the permit does have emission limits for startups, and it is therefore possible to compare those limits with the proposed Russell City permit limits.[116] The Caithness permit establishes two tiers of startup limits, one for when the auxiliary boiler is being used and one for when the auxiliary boiler is not being used. The Air District evaluated the limits for startups without the auxiliary boiler first, which is the scenario corresponding to the applicant's proposed design for Russell City. For NO_2 emissions, the Caithness startup limits are all higher than the limits the Air District initially proposed for the Russell City permit here. The Air District therefore concludes that Caithness further supports the reasonableness of these NO_2 startup limits as the lowest achievable BACT limits. At the very least, the Caithness permit cannot be read to suggest that lower NO_2 startup limits are warranted. The story is slightly different for CO startup emissions, however, as the Caithness permits limits for hot and cold startups are below the CO startup limits the Air District initially proposed for Russell City. Specifically, the Caithness hot startup limit for CO (without auxiliary boiler) is 891 pounds, which is significantly lower than the 2514 pound CO hot startup limit initially proposed for Russell City. Further, the Caithness cold startup limit for CO (without auxiliary boiler) is 2813 pounds, which is significantly lower than the 5028 pound CO cold startup limit initially proposed for Russell City. Upon further consideration, the Air District believes that revisiting the proposed Russell City limits for hot and cold startups would be appropriate in light of this new information from Caithness. The Air District is therefore lowering its proposal for the hot startup limit to 891 pounds of CO, based on the limit imposed in the Caithness permit for similar equipment. The Air District is also lowering its proposal for the cold startup limit to 2514 pounds of CO, based on the Caithness permit and on another lower permit limit the Air District examined in further considering this issue, the Sutter Power Plant. The Sutter facility has a permit limit of 2514 pounds of CO per cold startup and has been achieving this limit, and the Air District concludes that a 2514 pound limit would be achievable at Russell City as well.

Based on this review, the Air District has concluded that under this revised proposal, the Russell City startup limits will be as stringent as (or more stringent than) either Lake Side or Caithness

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contain daily emissions limits, towards which startup emissions are counted, but has no limits specifically for emissions during startups. In addition, the permit application provided startup information based on vendor data, which were referenced in the Utah DEQ analysis for the permit, but these numbers were for one specific operating temperature and were not presented as vendor guarantees of what the equipment could reliably achieve under all foreseeable operating circumstances. Moreover, the numbers do not identify whether they were for startups using the auxiliary boiler or not. *See* Notice of Intent and Prevention of Significant Deterioration Air Quality Application, Lake Side Power Plant (May 2004), Table 3-6.

[116] *Prevention of Significant Deterioration of Air Quality (PSD), Caithness Long Island Energy Center*, April 7, 2006 (with transmittal letter from W. Mugdan, Director, U.S. EPA Region 2, Division of Environmental Planning and Protection, to R. Ain); available at: www.caithnesslongisland.com/Final%20PSD%20Permt_4.7.06.pdf.

for startups without an auxiliary boiler. For ease of comparison, the Lake Side, Caithness and proposed Russell City permit limits are summarized in Table 5 below.

Table 5
Comparison of Lake Side, Caithness and Proposed Russell City Startup Emissions Limits (without Auxiliary Boiler)

Startup Scenario	Lake Side Permit Limit	Caithness Permit Limit	Proposed Russell City Permit Limit
Hot Startup	n/a	127 lbs. NOx	95 lbs. NO_2
	n/a	891 lbs. CO	891 lbs. CO
Warm Startup	n/a	488 lbs. NOx	125 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO
Cold Startup	n/a	488 lbs. NOx	480 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO

The Air District also considered the possibility of requiring an auxiliary boiler, which would presumably be able to achieve the lower emissions limits expressed in the Caithness permit applicable when the auxiliary boiler is used. Upon further consideration of this issue, the Air District has concluded that while auxiliary boilers are common technology in colder climates to keep equipment warm in cold weather, the costs associated with requiring such equipment at Russell City would not be justified by the relatively small startup emissions reductions that would be gained. (*See* discussion in Section VII C.2 below for the complete analysis.) The Caithness permit limits for this operating scenario are therefore not comparable to Russell City and the Air District does not consider them as indicative of what the Russell City facility will be able to achieve.

In summary, the Air District agrees with the comments that it should examine the Palomar, Lake Side, and Caithness facilities as potentially comparable facilities to determine if the startup limits in the Russell City permit are the lowest achievable. As outlined in this discussion, the conditions that the Air District is now proposing for this permit are the most stringent emissions performance levels that any of these facilities suggests is achievable for purposes of the BACT analysis. The Air District invites further comment on this additional analysis.

2. Startup Duration

The Air District also received some comments suggesting that the time it proposed to allow for startups is longer than it needs to be. The comments criticized the Air District's reliance on the startup limits for the Delta, Los Medanos, and Metcalf Energy Centers and the Sutter Power Plant in its analysis of the appropriate startup limits for Russell City, claiming that these facilities may not represent the best startup times achievable today using best work practices. The comments stated that the Air District should evaluate whether shorter startup timeframes would be achievable using best work practices, and cited one recent permit – for the Colusa Generating Station in Colusa, CA – that had been issued with shorter startup time limits of 4.5 hours for cold startups (compared with 6 hours proposed for Russell City) and 1.5 hours for hot startups (compared with 3 hours proposed for Russell City).[117]

At the outset, the Air District notes that startup duration, as opposed to startup emissions, is not technically subject to the BACT requirement. BACT is "an *emission limitation* . . . based on the maximum degree of *reduction for each pollutant*" achievable by the facility (40 C.F.R. § 52.21(b)(12) (emphasis added)). It is thus a limitation on the amount of pollution emitted, not on the duration of any particular operating mode. As long as a facility can achieve the lowest *emissions* from startups among sources of its type, the facility will satisfy BACT even if it has to take a longer *time* to get to steady-state operating conditions. The reason for this rule is obvious: it is the emissions that matter from an air quality standpoint, not the time involved, and so if two facilities can achieve the same emissions performance there is no air quality reason to prefer one startup duration over the other (and indeed if one can achieve lower total emissions but needs a longer time frame to do so, the longer lower-emissions startup should be encouraged). The Air District has traditionally included startup duration among its permit conditions because as a general rule shorter startups equate to lower startup emissions, but as long as the emissions rates are at the lowest level achievable the facility will satisfy BACT regardless of duration. Here, the Air District's evaluation has concluded that the Russell City Energy Center will be subject to the most stringent achievable startup *emissions* limits as explained in the initial Statement of Basis and as further refined in this Additional Statement of Basis, and so the facility satisfies the BACT requirement on that basis. Imposing an additional requirement on startup durations is not technically required by BACT.

Beyond this threshold point regarding BACT applicability, the Air District has in light of these comments considered further whether current best practices can achieve shorter startup times than what was achievable by the facilities that were permitted pre-2001, and has concluded that there is no reliable evidence that they can. The commenters do not cite any evidence of advances in startup performance since those facilities were permitted, and their criticism of the Air District's reliance on those facilities is based solely on the passage of time. Moreover, some of the commenters themselves cited contrary evidence, in the form of recent testimony before the California Energy Commission that using current technology, startups at combined-cycle facilities "can take a minimum of three and possibly six hours . . . ."[118] Based on this record, the Air District finds little compelling evidence that there have been any significant advances in operational practices in recent years that can reduce startup times.

The one recent permit the comments did cite on this issue is the Colusa permit, which the Air District reviewed in detail in response to this comment. Although that facility has not been built yet and so there are no actual operating data on which to assess its startup performance, the commenters are correct that the permit for the facility does include tentative initial time limits for

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[117] Note also that commenters on this subject cited emerging technologies that they claimed can reduce startup times, which are addressed in the technology choice section below. This section of the discussion focuses on the startup time limits that can be achieved using best work practices, without additional technologies that the Air District is not proposing to require as BACT.

[118] *See* Comments of Chabot-Las Positas Community College District, p. 11 (citing testimony before the California Energy Commission on December 18, 2008).

hot and cold startups that are shorter than the Air District is proposing for Russell City, as noted above.[119] But even if the facility will be able to achieve steady-state operation within these time limits, that does not mean that it will achieve better startup performance. To the contrary, the startup limits for the Russell City Energy Center will be *lower* than for Colusa, notwithstanding Colusa's shorter time limits. Specifically, the Colusa permit allows up to 779.1 pounds of NO_2 per cold startup and 259.9 pounds of NO_2 per hot startup.[120] By contrast, Russell City will be limited to 480 pounds of NO_2 per cold startup and 95 pounds of NO_2 per hot startup, approximately half the amount allowed at Colusa.[121] The Air District therefore concludes based upon its review of the Colusa permit that the Russell City proposed permit limits do satisfy the Federal PSD BACT requirement.

Finally, with respect to startup and shutdown durations, one commenter apparently understood that the Air District had conducted a BACT review for startups and shutdowns, but stated that the limits on startup and shutdown duration are not included in the permit conditions. To clarify this situation, the Air District refers to the proposed definitions of startup and shutdown. Startup and shutdown periods are defined with a maximum duration, and after the end of the startup and shutdown period the turbines have to comply with the more stringent emissions limits applicable during normal, steady-state operation. If the startup is not complete by the time the maximum

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[119] Because the facility has not yet been built, there is no evidence from this facility on which to rely other than the analysis and justification in the permitting agency's BACT analysis. But that analysis does not include any actual operating data showing that these limits are achievable. To the contrary, it appears that the permitting agency concluded that the startup limits satisfied BACT because the applicant had proposed them and because they were below the limits in other permits for similar facilities. (*See* Ambient Air Quality Impact Report, Colusa, at pp. 19-20.) Moreover, the permitting agency explicitly considered that the startup limits might not turn out to be achievable, explaining that if experience shows that they are unrealistic then they will have to be revaluated. (*See id.*) The Air District therefore finds it highly questionable whether the Colusa example provides any hard evidence on which to conclude that the short startup limits in the permit are achievable. The issue is moot, however, as regardless of startup times the Russell City permit limits require lower emissions than the Colusa permit limits.

[120] *See* Prevention of Significant Deterioration Permit, Colusa Generating Station (EPA Region 9, issued Sept. 29, 2008) at p. 8 (available at at www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436.

[121] The Air District notes that the Colusa startup limits for Carbon Monoxide are somewhat lower than the Russell City startup CO limits. (*See id.*) The fact that Colusa has higher NOx startup limits than Russell City in conjunction with lower CO startup limits highlights the NOx/CO tradeoff that the Air District noted in the Statement of Basis. The Air District does not agree with favoring reduced CO in exchange for increased NOx emissions because the Bay Area is in attainment of the applicable CO NAAQS but is non-attainment with the applicable ozone NAAQS (and NOx is an ozone precursor). The Air District therefore does not find that the Colusa permit provides evidence on which to justify a lower CO limit for startups. To the extent that the Colusa permit shows that lower CO startup limits are technically feasible, the Air District would reject them in favor of the limits it is imposing here based on the ancillary environmental impacts involved in going to those lower CO limits – that is, the increased NOx emissions that would be involved, as evidenced by the higher Colusa NOx limits.

startup duration has elapsed (*i.e.*, if the facility has not achieved normal, steady-state operation), the facility will have violated its permit conditions and will be subject to enforcement action.

C. BACT Technology Review

The Air District also received a number of comments regarding its analysis of the control technologies available to reduce startup emissions. A number of comments criticized the Air District's BACT technology review, claiming that certain technologies the Air District rejected should be required because they would result in lower BACT permit limits. Among the technologies cited in these comments were Fast-Start technology, which is an integrated system using a "once-through" steam boiler to reduce startup times; the use of an auxiliary boiler to keep equipment warm during shutdowns and therefore allow it to start back up more quickly; and Low-Load "turn down" technology, which aims to reduce emissions at lower loads and may potentially be effective to reduce emissions as the turbines ramp up to full load during startups. The Air District's has further analyzed these technologies in light of these comments, as follows.

1. "Fast Start" Once-Through Steam Boiler Technology

The Air District received comments asserting that "Fast Start" technology is available for combined-cycle facilities with higher-efficiency triple-pressure steam turbines of the type proposed for the Russell City facility. These comments claimed that the Siemens "Flex-Plant 30" design is available and could be used for this facility. The comments cited two projects – the Lake Side Power plant in Utah and the Caithness Long Island Energy Center in New York – that supposedly use FP-30 technology.

The Air District reviewed the situation regarding the availability of Fast Start technology in light of these comments. Siemens confirmed that no Flex Plant™ 30 has been constructed or proposed at this time for a full-scale power plant project. The term "Flex Plant™" is used to describe a family of Siemens' combined cycle "platforms" based on integration of one or more Siemens' SGT6-5000F gas turbines, a Siemens integrated cycle design and HRSG specification, a Siemens steam turbine, and a Siemens SPPA-T3000 control system[122] Siemens representatives have confirmed to the Air District that the Lake Side and Caithness facilities both use the same 501F turbine technology and conventional triple-pressure boiler technology as proposed for Russell City, *i.e*., they do not include a "once-through" Benson boiler.[123] According to Siemens,

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[122] Siemens Statement Regarding Available Siemens Technology Which Appear in Comments on RCEC's Draft PSD Permit (hereinafter, "Siemens Technology Statement"), received by email from Candido Viega, Region Vice President, Pacific Northwest, Siemens Energy, Inc., to Richard Thomas, Calpine, March 16, 2009.

[123] *Id.* The BACT analysis performed by the Utah Department of Environmental Quality's, Division of Air Quality also suggests that the Lake Side Power Plant does not reflect advanced technology, as alleged by one commenter. The engineering analysis says that "[t]he project will consist of generating equipment in a configuration that has been permitted and is in use throughout the United States and the world." *Engineering Review, Summit Vineyard, LLC, Lake Side Power Plant* (October 25, 2004) (hereinafter, "Lake Side Engineering Review"), at p. 5; available at: www.airquality.utah.gov/Permits/DOCS/ RN3031001-04.pdf.

"[n]either Lakeside [Power Plant] nor Caithness Long Island Energy Center (CLIEC) were represented as, nor [*sic*] sold as, a Flex Plant™ 30."[124] The Air District also contacted the plant manager from the Lake Side plant, who confirmed that the facility uses the Siemens 501F turbine with the latest FD3 technology, along with a conventional triple-pressure boiler and steam drum; the facility does not use a once-through boiler design.[125]

The commenters' confusion over whether these the Lake Side and Caithness facilities use Flex-Plant 30 technology may have arisen because they both use an auxiliary boiler to keep the equipment warm during cold weather.[126] The use of such an auxiliary boiler is common in colder regions where low temperatures can greatly prolong startups during cold weather, but such equipment does not constitute Flex-Plant™ 30 integrated plant design or similar "once-through" Benson boiler design. These two facilities do not, therefore, contradict the District's conclusion that Flex-Plant 30 technology is not yet available.

Regardless of this distinction in the types of technology used at Lake Side and Caithness, however, the Air District interprets the commenters' point to be that the Air District should consider whether to require the same type of technology used at those two plants to keep equipment warm and allow it to start up faster. The Air District considered the use of an auxiliary boiler as is used at Lake Side and Caithness, and its analysis is described in detail in subsection 2 below. As noted below, however, the Air District found that it would not be required as a BACT control because the economic impacts in having to install and operate the auxiliary boiler render it inconsistent with BACT, given the relatively small additional emissions reductions it would achieve. The Air District is therefore not requiring an auxiliary boiler as used at Lake Side and Caithness.

2. Use of Auxiliary Boiler

As noted above, in light of some of the comments that cited the Lake Side and Caithness facilities, which use an auxiliary boiler, the Air District considered whether it should require an auxiliary boiler to be used on this project. The District analyzed the startup emissions benefits of using an auxiliary boiler here in the context of the additional costs that would be involved. The District compared startup data from Calpine's facility in Mankato, Minnesota, a facility that is equipped with an auxiliary boiler. For some startups the plant uses the auxiliary boiler and for others it does not, and so the plant allows a direct comparison of the actual emissions reduction impact from using this technology. The data show that using the auxiliary boiler will reduce fuel usage (and consequently emissions) by approximately 18% for warm startups and approximately 31% for cold startups (with no impact on hot startups, as the HRSG and steam turbine are already at a high temperature).[127] Assuming an annual operating profile containing 6 cold startups and 100 warm startups (a conservative estimate because actual startups will likely be

[124] Siemens Technology Statement, *supra* note 122.

[125] Telephone conversation between Weyman Lee, BAAQMD Engineer, and John Bowater, Plant Manager, Lake Side Power Plant, April 8, 2008.

[126] *See* Lake Side Engineering Review, *supra* note 123, at pp. 6-7; Caithness Long Island Energy Center, *Environmental Impact Statement*, June 2005, at 9-35 – 9-36, available at: www.lipower.org/company/powering/caithness.html.

[127] *See* Excel spread-sheet entitled "Aux Boiler start profile DJ.xls".

lower), a similar reduction at Russell City from using an auxiliary boiler would result in 0.9 tons of NOx and 12.4 tons of CO per year.[128] The Air District compared these potential emissions reductions to the costs of using an auxiliary boiler, based on a cost estimate provided by Calpine and reviewed by the District.[129] That cost estimate showed that the annualized cost of $1,029,521 for the installation and operation of the auxiliary boiler. In terms of dollars-per-ton, these figures yields a cost-effectiveness number of $1,143,912 per ton for the NOx reductions and $83,025 per ton for the CO reductions. In light of these cost-effectiveness numbers, the costs of requiring an auxiliary boiler here would greatly exceed what any permitting agency would require in order to achieve this level of additional emissions reductions.

3. Use of Single-Pressure "Flex Plant 10" Technology

The Air District also received comments noting that two other proposed facilities for which applications have been recently submitted (Willow Pass and Marsh Landing) are proposing to use Flex-Plant 10 technology. (Flex-Plant 10 technology is similar to Flex-Plant 30 technology, except that is uses a single-pressure steam boiler instead of a triple-pressure steam boiler.) These comments suggested that these permitting applications show that Flex-Plant 10 should be reviewed for "its appropriateness at Hayward". Other comments took the opposite position, however, stating that Flex-Plant 10 technology is not appropriate for this type of facility. These comments stated that a Flex-Plant 10 system is appropriate for peaking-to-intermediate duty operations, whereas the Flex-Plant 30 system is the appropriate technology for intermediate-to-baseload operations. These comments were based on the observation that there is an energy efficiency penalty when using the single-pressure steam boilers system, compared with the more efficient triple-pressure system that is being proposed here. The Air District agrees with the latter comments. Flex-Plant 10 is an excellent technology to allow peaking-to-intermediate plants – which have to be able to start up and come on line very quickly – to gain the benefits from using combined-cycle technology (as opposed to less efficient simple-cycle turbines). But it is not appropriate for intermediate-to-baseload facilities where quick startup times are less important because of the energy efficiency penalty associated with using a single-pressure steam turbine. For intermediate-to-baseload facilities, it is preferable to obtain the better overall emissions performance achievable through the use of a triple-pressure system instead of using a less efficient single-pressure system like the Flex-Plant 10. (Note that when Flex-Plant 30 technology becomes available it will allow suitable triple-pressure systems to achieve faster startups as well, but this technology is not yet available for this project.)

A related comment objected to the District's comparison of Flex-Plant 10 technology as being less efficient than triple-pressure steam turbine systems. The comment asserted that Westinghouse 501F turbines can be between 36.5% and 56% efficient, and the comparison with the FP-10's stated efficiency of 48% might be different if it is made at an efficiency different from the 55.8% efficiency value the District used. The Air District believes that this commenter may be misunderstanding the efficiency ratings for these turbines, and would like to take this

[128] *See id*. Note that these reductions are net of the small additional emissions that would be generated by the auxiliary boiler itself. The Air District agrees with the commenters who stated that the emissions reductions from the auxiliary boiler would be more than offset by the startup reductions.
[129] *See* Excel spread-sheet entitled "Aux Boiler-NOx-2.xls".

opportunity to clarify the issue for the record. The 36.5% efficiency factor cited by the commenter for operation of an F-class turbine would be for operation in a simple cycle facility; that is, using the turbine only and not taking advantage of the waste heat in the turbine exhaust to generate steam for the combined-cycle heat recovery boiler. The proposed facility here is a combined-cycle facility that will have a heat recovery boiler to generate steam for additional electrical generation. The steam boiler that is being proposed here is a triple-pressure turbine that is more efficient than the single-pressure system used in the Flex-Plant 10 system. The Air District invites further comment on the Flex-Plant 10 issue to the extent that any commenters have misunderstood the technical basis of the Air District's analysis.

4. Low-Load "Turn-Down" Technology

The Air District received several comments asserting that it should require Op-Flex low-load "turn-down" technology as a BACT technology for reducing startup emissions. These comments noted that the Palomar facility in Escondido discussed above has installed Op-Flex technology, and argued that this fact demonstrates that the technology is technically feasible for reducing startup emissions. The comments also noted that the CEC staff suggested that Op-Flex should be required as BACT in a comment letter. Some of the comments stated that if the Air District does not require Op-Flex technology to be used, as an alternative it should require the same level of startup emissions reductions as achieved by other facilities with Op-Flex.

The Air District reviewed its assessment of Op-Flex in light of these comments. The Air District notes at the outset that the Federal PSD BACT requirement is ultimately an emissions limit, not a control technology *per se* (although, obviously, it must be based on the performance of the best available technology taking into account all relevant factors).[130] Based on the data that the Air District has reviewed from the Palomar facility that uses Op-Flex and early ammonia injection, the District has concluded that the Russell City facility will have startup emissions that are the same as or lower than startup emissions achieved at Palomar. (*See* discussion in Section VII B.1, above.) The Air District therefore agrees with the comments stating that the Air District should require the same level of startup emissions reductions achieved at facilities that have installed Op-Flex. The Air District disagrees, however, with the commenters who claimed that the Air District should specifically require the use of Op-Flex as a technology.

Moreover, the Air District does not find any reason to alter its BACT analysis of Op-Flex as not yet "available" for BACT purposes as an effective technology for reducing startup emissions. The Air District's conclusion was based upon the lack of a manufacturer's guarantee; the limited nature of the data from the only facility using Op-Flex, which is not sufficient to allow a determination that Op-Flex really is achieving any significant reductions in emissions beyond what is already achievable using other approaches; and the fact that no other permitting agencies have ever found Op-Flex to be an achievable technology for reducing startup emissions. None of the commenters has provided any reason to reconsider any of these rationales.

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[130] *See, e.g.*, *In re Three Mountain Power*, 10 E.A.D. 39, 54-55 (EAB 2001) (BACT is an emission limitation not a control technology and if two alternatives can achieve the same emissions performance the choice is in essence immaterial).

The Air District therefore continues to conclude that Op-Flex as not yet an available technology, and is appropriately eliminated in Step 2 of the Top-Down BACT analysis. Moreover, based on the additional analysis referred to above, even if the Air District were to address Op-Flex as an available technology in Step 3 of the Top-Down analysis, there is no indication based on the available data that it should be ranked higher than the alternative the District ultimately selected, best work practices. For all of these reasons, the Air District disagrees that Op-Flex should be required as the BACT technology for this facility.[131]

5. EPA Region 9's Colusa PSD Permit

The Air District also received comments that disagreed with the District's assertion that EPA Region IX does not require OpFlex as BACT, based on the permit Region IX issued for the Colusa Project. The comments noted that a commenter in the Colusa proceeding brought the issue to the Region's attention in a comment, but that the comment was withdrawn and so Region IX did not consider it. The comments requested that the District consider the comments that were submitted and subsequently withdrawn in the Colusa proceeding here.

The District agrees that that EPA Region IX did not formally respond to the withdrawn comments on the record. But once EPA was aware of the issue, it would not (and legally could not) fail to require OpFlex technology if that technology were BACT. The agency has an independent responsibility to impose BACT based on all of the information available to it, even if the specific comment that brought the issue to light was withdrawn. For this reason, the District stated in the initial Statement of Basis that EPA Region IX did not require OpFlex as BACT.[132]

[131] A comment also stated that the CEC found that Calpine rejected OpFlex because of the associated cost, and stated in this context that the District needs to ensure that its BACT analysis is "untainted" by considerations of things like costs. The District disagrees that cost was a part of the District's analysis of Op-Flex technology. The commenter has not identified any element of the Air District's BACT analysis regarding Op-Flex that is based on cost, and the District has not found any either.

[132] The same commenter also suggested that U.S. EPA Region 9's decision (or lack thereof) not to require OpFlex™ in the PSD permitting decision for Colusa Generating Station was irrelevant to the Air District's decision because the proposed Russell City Energy Center would be located in a populated metropolitan area designated as nonattainment for certain National Ambient Air Quality Standards. The Air District would note that the suggestion implicit in this comment – that the BACT standard should apply differently between a location in a "major metropolitan area" and one outside such an area – is without any basis in the federal PSD regulations. Further, to the extent that the commenter intended to suggest that PSD permits should not be issued or the BACT standard should be applied differently for sources located in non-attainment areas, the Air District notes that such sources are subject to non-attainment New Source Review for non-attainment pollutants. In those cases, the BACT determination would actually comprise a determination of the "Lowest Achievable Emissions Rate", which is not at issue in this permitting action.

Moreover, although the Air District pointed out that EPA had not required the use of OpFlex as BACT at Colusa, the Air District conducted its own case-by-case evaluation and reached its own independent conclusion that OpFlex should not be required as BACT here. That analysis, as further considered in this Additional Statement of Basis, provides a sufficient basis for the current permitting action regardless of EPA Region IX's analysis. The District continues to believe that EPA Region IX's conclusions lend further credence and support to its analysis, however.

Finally, as for considering the Colusa comments that were withdrawn, they were submitted in the Colusa proceeding and were not submitted on the record as comments in this proceeding, so the District is not obligated to respond to them. If the commenters believe that the Air District should consider them on the record in this proceeding, they have an obligation to submit them into the record for the Air District to review, but they did not do so here. Nevertheless, the Air District obtained a copy of the comments from EPA Region IX to ensure that it had researched all information that could have bearing on this issue, and found nothing whatsoever in those comments to suggest that OpFlex should be required here. The comment letter cited several of the same points about the Palomar Energy Center that have been raised in this proceeding, to which the Air District is responding in detail in this section.

6. <u>Siemens "Low-Load Carbon Monoxide" Technology</u>

Another comment claimed that, based upon telephone conversations with Siemens representatives, a low-load "turn-down" technology product is currently available for Siemens turbines. The Air District investigated this issue further, and reviewed communications from Siemens confirming in writing that it does not have a low-load product that is commercially available for F-class turbines. Siemens' LLOF product, known as "Low Load Carbon Monoxide" (LLCO), has been validated for G-class turbines as noted in the documentation the Air District relied on in the initial Statement of Basis. (*See* Statement of Basis at p. 41 and n. 33.) The Air District confirmed this with Siemens in response to this comment. Siemens reports that "LLCO validation for F-class turbine began in December 2008 and [is] currently in process [but] the validation for the F-class turbine has not been concluded."[133]

Further, for the reasons discussed in the section of this Response on the Air District's BACT analysis for greenhouse gas emissions (Section III), the Air District has found that use of G-class turbines in place of the Applicant's proposed F-class turbines does not constitute BACT for Russell City Energy Center. Rather, as discussed in Section III B.2, use of G-class turbines for a proposed nominal 600 MW combined-cycle power plant would require installation of a substantially smaller steam turbine, which would result in a significant reduction in the plant's overall efficiency rating. In light of the ancillary environmental and energy impacts that would result from this efficiency loss, the Air District in not requiring the use of G-class turbines as BACT for this project.

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[133] *See* Siemens Technology Statement, supra note 122.

7. Use of "Best Work Practices" as BACT for Startups

The Air District also received a comment objecting to the selection of Best Work Practices as the BACT control technique, characterizing this approach as "simply following 'operating instructions' ". In light of this comment, the Air District would like to clarify for the record that optimizing a facility's operating procedures to implement best work practices is an effective and well-accepted method of minimizing emissions from startups and shutdowns.[134] The Air District does not find that the commenter's characterization of this approach to minimizing emissions provides any reason to alter its BACT analysis.

[134] *See, e.g.*, Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, U.S. EPA Region I (Jan. 28, 1993); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Feb. 15, 1983); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Sept. 28, 1982).

VIII. COMMISSIONING PERIOD

The Air District received a comment suggesting that the Air District should require a shorter commissioning period. The comment stated that the data the District reviewed demonstrates that a shorter time is feasible (citing examples of 96 hours and 207 hours taken to commission certain other turbines). The Air District reviewed the commissioning period BACT analysis in light of this comment, and does not believe that the data shows that a shorter commissioning period is feasible. The data shows that the time required for commissioning varies greatly from turbine to turbine, and that a reasonable allowance must be made for this variability. The data the Air District evaluated shows that although on occasion facilities have been able to complete commissioning in as little as 96 hours, on other occasions they have required as long as 297 hours. Based on this data, as well as the Air District's review of the applicant's estimate of the time that will be required, the Air District concludes that 300 hours is a reasonable time limit. The Air District therefore disagrees with this comment that a shorter time period is feasible as a BACT requirement.

IX. SULFURIC ACID MIST ISSUES

The Air District received a few comments on sulfuric acid mist, and takes this opportunity to clarify the record with respect to the issues raised.

First, the Air District received comments questioning the District's assertion that emissions of sulfuric acid mist are difficult to estimate because the conversion of fuel sulfur to SO_3 and then to H_2SO_4 is not well established. These comments suggested that the District should be in a position to explain more precisely what actual sulfuric acid mist emissions will be. The comments also questioned whether the facility will in fact emit less than the 7 tons-per-year PSD significance threshold. In addition, some comments claimed that the permit should limit sulfuric acid mist emissions to less than 38 pounds per day. The Air District has reexamined its analysis of sulfuric acid mist emissions in light of these comments, and has concluded that its initial analysis is sound. As explained in the initial Statement of Basis, Air District has estimated sulfuric acid mist emissions as accurately as it can, and believes that emissions will be below 7 tons per year. The Air District is not aware of any data or analysis suggesting that emissions will be over 7 tons per year, and none of the comments on this issue cited any, and so the Air District continues to believe that this is an accurate assessment. Moreover, the Air District is not simply relying on this estimate to ensure that emissions will in fact be below 7 tons per year. The permit includes an enforceable sulfuric acid mist limit to ensure that emissions stay below this level, and the facility will be required to conduct compliance testing to ensure that they do. This testing requirement will ensure that actual emissions are below 7 tons per year, regardless of the accuracy of the Air District's estimate. With respect to the need for a daily 38-pound emissions limit, EPA's Federal PSD permitting requirements regulate sulfuric acid mist on an annual basis and require annual emissions to be below 7 tons per year if a BACT analysis is not conducted. The Federal PSD requirements in 40 C.F.R. section 52.21 do not break that 7 tpy threshold down into a daily emissions limit.

The Air District also received comments questioning whether annual compliance testing will be adequate to ensure compliance with the 7 tpy permit limit. Comments suggested that the facility might simply "retest in the absence of oversight until compliance is demonstrated." Comments suggested that the District establish specific test dates "to prevent test manipulation by retesting." The Air District considered this issue as well, and notes that the permit conditions require all non-compliance to be reported to the Air District. (*See* Proposed Permit Condition No. 37.) Thus, any non-compliance discovered during a compliance test will be reported, and the facility will not be allowed to keep a failed test secret and conduct a further test to show compliance. The Air District has therefore concluded that the compliance testing requirements as proposed will not allow the potential for "test manipulation by retesting".

Finally, some comments also cited a paper on new methodologies for estimating total sulfuric acid emissions from power plants. The Air District is unclear as to why the commenters consider this paper relevant, as the comments did not explain how this information pertains to this permitting action. The Air District has reexamined the issue of sulfuric acid testing methodologies, however, to the extent that these comments were intended to question the testing methodologies that will be used to determine compliance with the permit limits. The Air District notes in this regard that any testing methodology must be approved by the Air District. This approval requirement ensures that the Air District can require the most accurate and up-to-date testing methodologies to be used. The Air District acknowledges the information provided by these comments, but does not find anything in it to suggest that the proposed permit conditions should be changed in some way. The Air District solicits further input on this additional discussion regarding sulfuric acid mist issues.

X. MONITORING ISSUES

The Air District also received some comments on the proposed monitoring requirements for the facility. The Air District has conducted further review and analysis of the proposed monitoring requirements, as explained below.

One comment claimed that the proposed monthly monitoring of the sulfur content of the facility's natural gas fuel is not frequent enough. The comment claimed that the sulfur content of the natural gas can vary significantly from one quarter to another (citing data tabulations from PG&E's website), and states that for this reason "the need for increased accuracy is essential". The commenter suggested weekly sulfur monitoring, in order to "assure the accuracy" of monitoring of sulfur content. The Air District considered this issue further in light of this comment, and has concluded that weekly monitoring is not necessary to ensure compliance with the natural gas sulfur limits. The comment claims that sulfur content can vary from quarter to quarter, but even if this is so, a monthly testing requirement will be able to track such variations. The comment did not point to any evidence that the additional data that could be gained from weekly monitoring would be worth the additional burden of doing so, and the Air District is not aware of any.

Another comment criticized the District's proposal to allow Russell City to use PG&E's monthly gas sulfur content measurements if the facility can show that they are 'representative'. The commenter objected that "there are no objective criteria specified in the permit conditions as to what qualifies as 'representative' ". The commenter also claimed that "PG&E adds chemicals to its natural gas" and "does not assure the accuracy of its published information". The Air District reviewed the proposed requirements for sulfur monitoring in the draft permit in light of this comment, and has concluded that they are adequate to ensure compliance. The sulfur monitoring condition allows the facility to use PG&E data only if the facility can demonstrate that the data is representative. PG&E data will not be acceptable if it is not accurate. Moreover, "representative" has a well-understood meaning and does not need "objective criteria" to define it further. In plain English, this proposed condition would require that the PG&E data provide a true and accurate picture of the actual sulfur content of the natural gas to be acceptable. The Air District has therefore concluded that the proposed condition allowing the use of representative data from PG&E does not need to be revised.

Another comment stated that ASTM fuel sulfur analysis methods were updated to correspond to NSPS Subpart GG as revised July 2004. With respect to the information about the ASTM fuel sulfur analysis methods, the Air District acknowledges the information but does not find anything in the comment suggesting that the proposed permit conditions need to be changed. The condition requires accurate testing of the sulfur content of the natural gas, and the fact that testing standards may have been revised is not inconsistent with this requirement.

Another comment stated that the District should require more stringent monitoring for PM emissions. The comment asserted that PM emissions can increase from poor air/fuel mixing or maintenance problems, and that the District should require more frequent monitoring to ensure that such problems do not go undetected. The Air District has reviewed this issue as well in light of this comment, and disagrees that annual compliance testing for particulate matter emissions is inappropriate. A primary factor influencing PM emissions is sulfur content in the natural gas, which will be monitored on a monthly basis. To the extent that poor air/fuel mixing or similar combustion problems (whether related to maintenance problems or otherwise) might also increase PM emissions, those conditions would also be manifested in higher Carbon Monoxide emissions. Carbon Monoxide emissions are monitored on a continuous basis, and so the problems would be detected and addressed immediately. The Air District does not find that it would be necessary to add more frequent PM monitoring as well to address these concerns.

XI. AIR QUALITY IMPACT ANALYSIS ISSUES

This section addresses the source impact analysis and additional analyses required by the Federal PSD regulations.

A. Air Quality Impact Analysis Issues

The Air District first addresses comments related to the PSD Air Quality Impact Analysis is has prepared for this project.

1. Use of NSR Workshop Manual As Guidance For AQIA

The Air District received a comment questioning the District's use of EPA's 1990 Draft NSR Workshop Manual as guidance for conducting the Air Quality Impact Analysis. The commenter noted that the NSR Workshop Manual is not a binding regulation, and suggested that it may have been superseded by more recent EPA regulatory enactments. In response to this comment, the Air District wishes to clarify that although the NSR Workshop Manual is not binding as the commenter points out, it does provide a useful framework for conducting an Air Quality Impact Analysis. The Air District therefore uses the NSR Workshop Manual as guidance in situations where there is not any other more authoritative binding guidance that has been provided by EPA. The comment did not point out any specific area where the Air District's reliance on the NSR Workshop Manual was improper, and the District is not aware of any. If any member of the public considers the Air District's use of the NSR Workshop Manual to have been improper in any respect, the Air District invites the public to comment further on how such reliance may have been improper and what other guidance or procedure the District should follow instead.

2. Use of Highest Modeled PM_{10} Value for Comparison With SIL

The Air District also received comments stating that it should use the highest modeled PM_{10} value to compare with the ambient air quality impact significance threshold, not the sixth-highest value as used in the initial Statement of Basis. The Air District believes that use of the sixth-highest modeled value is consistent with EPA's modeling guidelines, which specify that the sixth-highest modeled value should be used to compare with the significance threshold.[135] As 40 C.F.R. Part 51 Appendix W states, "[f]or the 24-hour PM-10 NAAQS (which is a probabilistic standard)—when multiple years are modeled, they collectively represent a single period. Thus, if 5 years of [National Weather Service] data are modeled, then the highest sixth highest concentration for the whole period becomes the design value." Furthermore, the EPA guideline model AERMOD is hardcoded with an algorithm using the sixth-highest daily concentration; if another approach is to be used, the guideline approach has to be overridden.[136] For these reasons,

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[135] *Guideline on Air Quality Models*, 40 C.F.R. Part 51, Appendix W (July 1, 2008) (hereinafter, "Appendix W Modeling Guideline"), § 7.2.1.1.b., applicable to PSD Air Quality Impact Analyses per 40 C.F.R. § 52.21(*l*)(1).

[136] *See* Section 3.2.5 Specifying the Pollutant Type of User's Guide for the AMS/EPA Regulatory Model-AERMOD - EPA-454/B-03-001, September 2004.

the Air District concludes that the best reading of the EPA guidance on this issue is that it requires the sixth-highest modeled value to be used for the PM_{10} analysis.

Nevertheless, in response to this comment the Air District evaluated the potential impacts from using the highest modeled value for the PM_{10} analysis. The Air District found that using the assumption that the cooling tower water could have up to 8,000 ppm (by weight) Total Dissolved Solids (TDS), the highest modeled value would exceed the PM_{10} Significant Impact Level of 5 $\mu g/m^3$. The Air District therefore explored with the applicant whether it could keep TDS levels within a lower limit. The applicant found that it could keep TDS within a limit of 6,200 ppmw, and so the Air District is lowering the TDS limit in the permit to that level. With the TDS limit reduced to 6,200 ppmw, the cooling tower's PM_{10} emissions would be reduced accordingly:

TDS:	8,000 ppmw	6,200 ppmw
Hourly PM_{10}	2.83 lbs	2.19 lbs
24-hour PM_{10}	67.9 lbs	52.6 lbs
Annual PM_{10}	12.1 tons	9.4 tons

The AERMOD modeling analysis was then re-run using a new pollutant ID to enable the program to predict the highest-high 24-hour concentration, and with the revised PM_{10} emissions rate. The analysis showed a highest modeled 24-hour PM_{10} concentration of 4.9 $\mu g/m^3$, which is below the Significant Impact Level. The Air District is revising proposed Condition No. 44 to in the final permit reflect this lowered TDS limit.

3. Representativeness of Meteorological and Background Air Quality Data

The Air District also received comments questioning the representativeness of the meteorological data and background air quality data that the District used in its analysis. The comments suggested that that meteorological data from Oakland Airport and the background ambient air quality data from the Fremont-Chapel Way Monitoring Station would not be representative of the project location. The comments also questioned why the District does not maintain a monitoring station in Hayward.

In response to these comments, the Air District would like to clarify that the meteorological and background air quality are representative of air quality in the vicinity of the project location. For the meteorological data, data from the Automated Surface Observing System (ASOS) at the Oakland International Airport was used. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. The Oakland meteorological surface data (OAK) is representative of conditions at the Russell City Energy Center project site, based upon the requirements for representativeness set forth in the EPA's Guideline on Air Quality Models.[137]

[137] *See* Appendix W Modeling Guideline, *supra* note 135, Section 8.3 (Meteorological Input Data).

The Guideline on Air Quality Models states the following conditions should be considered when determining if weather data is representative: (1) The proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected. The Oakland Airport data satisfies all four of these criteria for representativeness and is appropriate for modeling the proposed project. Both the Oakland Airport and the proposed project location are along the East Bay shoreline with similar predominant upwind fetches. The AERSURFACE analysis showed that both sites had similar land use characteristics. Both sites are located on simple terrain in similar proximity to the complex terrain to the east. The Oakland Airport site is a permanent National Weather Service/Federal Aviation Administration weather installation that operates 24 hours per day. The most recent five years of data at the time (2003-2007) were used for this modeling study. Based upon this comparison, the Oakland ASOS data were considered representative of the proposed project location and met all USEPA data completeness requirements.

With respect on ambient air quality data from the Fremont-Chapel Way monitoring station, the District notes at the outset that in the initial Source Impact Analysis it conducted in connection with its December, 2008, proposal, all of the modeled impacts for the regulated PSD pollutants examined in that analysis were below the SILs. Because all modeled impacts were below the SILs, no full impact analysis was required and background data did not have to be used. The Additional Impacts Analysis did take background levels into account in examining whether the facility's emissions, plus background concentrations, would cause ambient air concentrations at levels that might impact soils and vegetation. The District therefore wishes to clarify that the background data from the Fremont-Chapel Way station is representative for these purposes. That data is representative of the background air quality at the project location based upon the criteria EPA has established for assessing representativeness. EPA provides for monitoring data of this type to be used if it is sufficiently representative based on three factors: (i) monitor location, (ii) the quality of the data, and (iii) the currentness of the data.[138] The Fremont-Chapel Way data is representative under all three of these criteria. The Fremont-Chapel Way monitoring station is located approximately 18 km southeast of the project in an area within the same air basin and with the same general geography and level of development. In addition, the data from the Fremont-Chapel Way monitoring station is complete and of high quality, and it is current (2006-2008). The Air District therefore concluded that the Fremont-Chapel Way monitoring data is representative and appropriate for use in assessing the impacts from the proposed facility.[139]

In response to the comments suggesting that the Air District should establishing a monitoring station in Hayward, the Air District notes that maintaining a monitoring station is an expensive endeavor, and given the District's resource constraints it can only maintain a certain number throughout the entire Bay Area. The Air District maintains several monitoring sites in the East

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[138] *See* NSR Workshop Manual, *supra* note 34, Section III.A., p. C.19.

[139] Note also that a full impact analysis was required for $PM_{2.5}$, based on regulatory developments since the initial Statement of Basis was published, and that analysis requires the use of $PM_{2.5}$ background monitoring data. Representativeness of the $PM_{2.5}$ data specifically is discussed further below in the discussion of the $PM_{2.5}$ source impact analysis.

Bay, which provide a good understanding of air quality conditions in the area given the District's resource constraints. The Air District will consider the needs for a monitoring station in Hayward, and in all other relevant areas in the East Bay and larger Bay Area, in its future planning for maintaining a representative monitoring network that will give an accurate picture of ambient air quality conditions.

4. Designation of Site as "Rural" for AERMOD Modeling:

The Air District received comments questioning whether the site location should have been designated as "rural" for the purposes of the AERMOD air quality impact modeling, given the development to the east of the project site. In this context, the commenters alluded to the fact that some areas near the project may be zoned for and used as urban, industrial land. In response to this comment, the Air District would like to clarify for the record that the "Rural" designation for purposes of AERMOD modeling is simply a variable that is used as an input in the model. It reflects the fact that the level of development in the project area is not of the intensity where increased surface heating would be expected due to the urban heat island effect. This designation is a 'term of art' based on an Auer land use analysis. The Air District's selection of the "Rural" designation for purposes of AERMOD modeling does not mean that the District considers the entire area to be rural in character. The Air District agrees with the commenter that areas in the project vicinity are light industrial in nature, but would like to clarify for the record that this does not mean that running the AERMOD model with a "rural" setting is inappropriate. To the contrary, the "rural" designation is appropriate for this facility based on the Auer land use analysis.

5. Completeness of Information Presented in Analysis

The Air District received comments suggesting that the Air Quality Impact Analysis's Table II (which presents emissions rates used for modeling for different pollutants and averaging times) and Table III (which presents the maximum predicted ambient air quality impacts that would result from the project) are incomplete. In light of these comments, the Air District would like to clarify for the record that certain boxes in these tables do not have data in them because they are not applicable. For example, in Table II, there are no emission rates provided for NO_2 and CO for the cooling tower because the cooling tower is not a source of emissions of these pollutants. To give another example, short-term emission rates are not provided for NO_2 because the NO_2 standard is an annual standard. The Air District did not put data in these boxes because it was not relevant to the PSD Air Quality Impact Analysis. If any members of the public believe that there is any data that is relevant and necessary to the Air District's that the Air District has overlooked, the District invites the public to comment further on what specific data is missing and how it would impact the outcome of the analysis.

6. Update to 2007 Air Quality Impacts Analysis:

The Air District received comments pointing out some changes that the District made to its Air Quality Impact Analysis it issued in connection with its December 2008 Statement of Basis and proposed permit compared with the analysis issued in connection with the District's 2007 permitting actions. For example, the comments pointed out that the analysis used for the

December 2008 Statement of Basis concludes that the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$, whereas the analysis used for the 2007 permitting actions states that it will be 370 $\mu g/m^3$. In light of these comments, the Air District would like to take the opportunity to clarify the record on this issue. The modeling for the 2007 permitting actions was performed using the model ISCST. EPA has made that model a non-guideline model, and it has been replaced with AERMOD, the current EPA guideline model. The analysis used for the December 2008 Statement of Basis was performed using AERMOD, and represents the current best assessment of what project impacts will be. As the commenter noted, the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$.

B. Air Quality Impact Analysis for $PM_{2.5}$

As noted above in Section VI in the discussion of Particulate Matter issues, EPA has stayed and proposed to repeal its exemption that provided for the analysis of PM_{10} impacts as a surrogate for analyzing $PM_{2.5}$. Because EPA has changed its position on the use of this surrogate policy, an analysis of $PM_{2.5}$ impacts is required for this permit. The project applicant therefore conducted an Air Quality Impact Analysis for $PM_{2.5}$ in conjunction with the Air District,[140] and the District has reviewed and documented the results of that analysis.[141] This section briefly sets forth the results of this analysis.[142]

1. Source Impact Analysis (40 C.F.R. § 52.21(k))

The principal element of the Air Quality Impacts Analysis is the source impact analysis required under 40 C.F.R. Section 52.21(k), which is designed to ensure that the project's emissions will not cause or contribute to any violation of the NAAQS or any established PSD increment. The source impact analysis is a two-step process that compares the projected air pollutant concentrations in the ambient air around the facility's location with the NAAQS and PSD increments. The first step in the process is to evaluate the air pollutant concentrations that would result from the project by itself, without any additional contributions from other sources. If the project's contribution would be less than "Significant Impact Levels" ("SILs") adopted by EPA, then the project is presumed not to cause or contribute to any exceedance of any NAAQS or PSD Increment and no further analysis needs to be conducted.[143] EPA has explained that it considers

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[140] *See* Atmospheric Dynamics, Inc., *$PM_{2.5}$ PSD Source Impact Analysis for the Russell City Energy Center Draft Prevention of Significant Deterioration (PSD) Permit* (July 30, 2009) (hereinafter, "Applicant's $PM_{2.5}$ Source Impact Analysis").

[141] *See* Summary of Air Quality Impact Analysis for $PM_{2.5}$ From the Russell City Energy Center, attached to Memorandum from Glen Long to Weyman Lee, July 27, 2009 (hereinafter, "Summary of $PM_{2.5}$ Air Quality Impact Analysis").

[142] Several comments criticized the use of the surrogate policy and stated that the District should conduct a $PM_{2.5}$-specific analysis. The District's analysis set forth in this section responds to those comments.

[143] *See* NSR Workshop Manual at pp. C.24-C.25.

sources whose impacts fall below the SIL will have at most a *de minimis* impact on air quality concentrations.[144]

If the concentrations from the project by itself would be above the Significant Impact Level, a full impact analysis is required based on multi-source modeling. The full impact analysis considers the project's contribution to ambient air pollution levels in conjunction with the contributions from other nearby sources and background levels to determine what the total ambient air concentrations would be if the project is built. If the total ambient air concentrations would not exceed the NAAQS at any location, or the project's contribution is below the Significance level at every location where the NAAQS would be exceeded, then the project does not "cause or contribute to air pollution in violation [a] national ambient air quality standard" within the meaning of 40 C.F.R. section 52.21(k)(1). If the total concentrations would exceed the NAAQS, and the project's contribution to that exceedance is above the Significance level at the location of the exceedance, then project is not eligible for a PSD permit.[145]

For $PM_{2.5}$, EPA has proposed three different alternative sets of SILs, but has not finalized its decision on which one to adopt.[146] To address this situation most conservatively, the Air District is proposing to use the lowest of the proposed SILs, which are 1.2 $\mu g/m^3$ for 24-hour average $PM_{2.5}$ concentrations and 0.3 $\mu g/m^3$ for annual average $PM_{2.5}$ concentrations. The Air District has found that emissions from the project by itself will cause ambient $PM_{2.5}$ concentrations above both of these SILs. For 24-hour average concentrations the project will have a maximum impact of 4.9 $\mu g/m^3$, and for annual average concentrations the project will have a maximum impact of 0.5 $\mu g/m^3$.[147] Because the project's contribution will be above these significance thresholds, a full impact analysis must be conducted utilizing multi-source modeling.

The first element of the full impact analysis is to define the "impact area" within which ambient concentrations must be evaluated through multi-source modeling. The "impact area" for this analysis is a circular area centered on the project location and extending outwards to the most distant point where the project's impacts are modeled to be above the SIL. Once the impact area is defined, the analysis then requires the project's contributions to be added to background ambient $PM_{2.5}$ concentrations obtained from air quality monitoring data, as well as emissions from any other point sources in the vicinity of the proposed project that should be addressed in addition to the contributions accounted for by the background monitoring data. All of these contributions must then be added together to determine whether the project's emissions will cause or contribute to any violation of the NAAQS within the impact area.

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[144] *See* Proposed Rule, "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)", 72 Fed. Reg. 54112, 54138-39 (Sept. 21, 2007) (hereinafter, "Proposed $PM_{2.5}$ Increment, SIL & SMC Rule").
[145] In such cases, a project applicant can agree to shut down existing sources in the area to reduce ambient air pollutant concentrations such that there will be no exceedances of the NAAQS after the project is built.
[146] *See* Proposed $PM_{2.5}$ Increment, SIL & SMC Rule, *supra* note 144.
[147] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, Table III.

The District used monitoring data from its Fremont-Chapel Way monitoring station as a measure of background ambient air quality. Ambient air quality data from this monitoring station is representative of the background conditions in the vicinity of the proposed project, and it satisfies all of EPA's requirements for representativeness as discussed above. EPA provides that regional monitoring data can be used as long as it is representative, based on (i) monitor location, (ii) the quality of the data, and (iii) the currentness of the data.[148] The Fremont-Chapel Way data is highly representative under all three of these criteria. The Fremont-Chapel Way monitoring station is located approximately 18 km southeast of the project in an area within the same air basin and with the same general geography and level of development. Moreover, $PM_{2.5}$ emissions in the wintertime (when particulate matter ambient concentrations are the worst) are similar at the Fremont-Chapel Way monitoring station and the proposed project site, further suggesting that background ambient concentrations are similar as well. (In fact, emissions at Fremont-Chapel Way monitoring station are slightly higher, suggesting that this is a conservative choice of representative monitoring data.) In addition, the data from the Fremont-Chapel Way monitoring station is of high quality and is current (2006-2008). The Fremont-Chapel Way station is also sited and operated in accordance with EPA's ambient monitoring data requirements set forth in EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (May 1987). For all of these reasons, the data satisfies EPA's requirements for representativeness of the background ambient air quality at the proposed project's location. The three-year average of the 98th percentile 24-hour average is 29.0 $\mu g/m^3$ and annual average is 9.5 $\mu g/m^3$.[149]

After background concentrations from air monitoring data are added, any other nearby point sources that are expected to cause a significant concentration gradient in the vicinity of the proposed project must be modeled. The contributions from all of these sources (the project itself, general background concentrations, and nearby point sources) are then summed and compared against the NAAQS at each modeled location within the impact area.[150] If, at any location within the impact area, the project's contribution is above the SIL, and the total of all contributions from all sources is above the NAAQS that that location, then the PSD requirements are violated. Conversely, if for each modeled location within the impact area, either (i) the total contribution from all sources is below the NAAQS or (ii) the project's contribution is below the SIL, then the project satisfies the PSD requirements.[151]

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[148] EPA regulations provide that a project can be excused from the requirement to use actual monitoring data in its PSD analysis where the project's contribution to ambient air concentrations will be less than EPA's Significant Monitoring Concentration leves ("SMCs"). As with the $PM_{2.5}$ SILs, EPA has proposed three separate alternative sets of SMCs, but has not finalized its selection of which one should be used. The District is therefore conservatively proposing to assume that the lowest SMCs will be chosen. The project exceeds these lowest most-conservative SMCs.

[149] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, Table V.

[150] Per EPA regulations, the 98th percentile concentration predicted by the model is used to compare with the NAAQS. *See* Appendix W Modeling Guideline, *supra* note 135, § 10.1.c.

[151] *See* NSR Workshop Manual, *supra* note 34, at p. C.52 ("The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation.").

The Source Impact Analysis undertook this exercise for both the 24-hour NAAQS and the annual NAAQS as discussed below, and also considered concerns regarding $PM_{2.5}$ increments and Class I impacts.

- *24-Hour NAAQS Analysis*

For the 24-hour standard, modeling of the facility's potential ambient air quality impacts showed emissions over the most-conservative 1.2 $\mu g/m^3$ SIL. The receptor locations where the facility's impacts were over the SIL were mostly within the immediate vicinity of the facility out to a distance of up to 1.26 km, but also at six specific more remote spots in the East Bay hills out to a furthest distance of 8.1 km. The Air District therefore considers the "impact area" for the full impacts analysis to consist of a circle around the facility with a radius of 8.1 km. For the full modeling analysis, the Air District considered the cumulative impact of the facility's emissions, background ambient air concentrations, and emissions from other nearby sources on receptors located within this impact area.

The facility's contribution was based on modeling using the facility's emissions, and the background contribution was based on the Fremont-Chapel Way monitoring data as discussed above. For the contribution from other nearby sources, the Air District undertook a search of its database of $PM_{2.5}$ sources within a radius of six miles (9.7 km) around the facility location that have been permitted since January 1, 2007, and located a total of 29 such sources (21 of which are diesel backup generators). The Air District also evaluated non-point sources within this area that could cause a significant concentration gradient at any of the areas where the facility's impact was above the SIL. The Air District identified a portion of Highway 92 that is located approximately 1 km south of the facility as such a non-point source, and included it in the analysis. The cumulative impact from all of these contributions (the facility, the 29 point sources, and Highway 92) was then modeled for each receptor location within the impact area where the facility's impact was above the SIL.

Based on this cumulative analysis, the District evaluated whether the highest 98th percentile (highest 8th high) $PM_{2.5}$ ambient air concentrations would be above the NAAQS at any receptor location where the project's contribution would be above the most-conservative 1.2 $\mu g/m^3$ SIL.[152] This evaluation examined whether the modeled concentration from the proposed facility plus other modeled sources would be above 6.0 $\mu g/m^3$ at any such receptor location, because the background level is 29.0 $\mu g/m^3$, meaning a further increase above 6.0 $\mu g/m^3$ would exceed the 24-hour NAAQS of 35 $\mu g/m^3$. The analysis concluded that there would not be any locations where both the project's contribution would be above 1.2 $\mu g/m^3$ and the total contribution from the project plus the other modeled sources would be above 6.0 $\mu g/m^3$. The Analysis found some locations where the total contribution from all modeled sources was over 6.0 $\mu g/m^3$. For example, the highest 98th percentile modeled concentration from these sources was 11.27 $\mu g/m^3$. But in each of these situations, the project's contribution at that location was well below the SIL,

[152] EPA guidance requires the highest 98th percentile value is used because compliance with the NAAQS is determined on this basis. *See* Appendix W Modeling Guideline, *supra* note 135, Section 10.1.c.

meaning that the project would not be causing or contributing to any NAAQS violation within the meaning of Section 52.21(k). Similarly, the analysis found some locations where the project's contribution was above the SIL, but in each of these situations the total contribution from all modeled sources was below 6.0 $\mu g/m^3$. This situation arises from the fact that when the wind is from the northwest, the project's impacts can sometimes exceed the SILs, but at those times the wind is blowing the contributions from other sources (such as Highway 92) in the other direction and not causing an exceedance of the NAAQS. Similarly, when the wind is blowing from the Southeast emissions from sources like Highway 92 can cause exceedances of the NAAQS within the impact area, but at those times the wind is blowing the project's contribution the other way such that the project's emissions are below the SIL. The proposed project therefore satisfies the Section 52.21(k) NAAQS compliance requirements for the 24-hour $PM_{2.5}$ standard.[153]

- *Annual NAAQS Analysis*

For the annual-average $PM_{2.5}$ NAAQS, the Source Impact Analysis conducted a similar multi-source modeling analysis. The impact area for the annual analysis is the same as the larger area for the 24-hour analysis, because the largest radius applicable to any averaging period should be used in establishing the impact area. The impact area for the annual analysis therefore extends out to the same 8.1 km distance from the facility as with the 24-hour impact area. The Air District conducted a cumulative analysis adding the contributions from the facility and the other modeled sources identified above plus background levels. This analysis found that the maximum total combined annual-average ambient air concentration would be 10.56 $\mu g/m^3$, which is well below the annual NAAQS standard of 15 $\mu g/m^3$. The proposed project therefore satisfies the Section 52.21(k) NAAQS compliance requirements for the annual $PM_{2.5}$ standard as well.[154]

- *PSD Increment Consumption Discussion*

With respect to exceedance of any PSD Increment for $PM_{2.5}$, the project cannot cause any such exceedance because EPA has not established any $PM_{2.5}$ increments yet. EPA has proposed increments, however, and so the District examined whether the facility would exceed any increment if they had been finalized. EPA's proposed Class II increments are 9 $\mu g/m^3$ and 4 $\mu g/m^3$ for the 24-hour and annual standards, respectively, and the facility's maximum impacts of 4.9 $\mu g/m^3$ and 0.5 $\mu g/m^3$, respectively, are well below these levels. Thus even if the proposed increments were in effect today, the facility would not cause any exceedance of them.[155]

- *Class I Areas Analysis*

Finally, EPA also requires an analysis of the potential for impacts to any Class I areas within 100 km of the proposed facility. Point Reyes National Seashore is located approximately 62 km from the project, so the Air District conducted a Class I area impact analysis for $PM_{2.5}$. The District

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[153] *See* further detailed analyses in Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141; and Applicant's $PM_{2.5}$ Source Impact Analysis, *supra* note 140.
[154] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, at p. 11.
[155] *See id*.

used the previously-conducted AERMOD analysis for PM_{10} impacts, and conservatively assumed that all of the PM_{10} from the project is $PM_{2.5}$. The AERMOD analysis showed that the particulate matter impact would be only 0.06 $\mu g/m^3$ at Point Reyes National Seashore, which is well below EPA's significance level of 1.0 $\mu g/m^3$. The Air District therefore concludes that the project will not have any significant air quality impact on any Class I area.[156]

2. Additional Impact Analysis (40 C.F.R. § 52.21(o))

In addition to the Source Impact Analysis required under 40 C.F.R. section 52.21(k), the PSD regulations also require an additional impacts analysis under 40 C.F.R. section 52.21(o). This additional impacts analysis consists of an analysis of visibility impacts, of soils and vegetation impacts, and of impacts from general commercial, residential, industrial and other growth associated with the project.

The District conducted a visibility impairment analysis using EPA's VISCREEN model and also with the Calpuff model. Both analyses show that the proposed project's $PM_{2.5}$ emissions will not cause any impairment of visibility at Point Reyes National Seashore.[157]

The District also added a $PM_{2.5}$ analysis to its revised Soils & Vegetation analysis, which is discussed in more detail in the next section. As explained there, the Air District concludes that the project's $PM_{2.5}$ emissions will not have any significant adverse impacts on soils and vegetation.

Finally, the District's associated growth analysis is not impacted by EPA's stay of the PM_{10} surrogate policy and by the inclusion of $PM_{2.5}$ impacts in the Air Quality Impacts Analysis. The District's associated growth analysis is set forth in the initial Statement of Basis at p. 16. Specific Associated Growth issues are also addressed in further detail in Section XI.D. below.

C. Revised Soils & Vegetation Analysis

The Air District received a number of comments on its Soils and Vegetation analysis. The Air District has now revised its analysis, based on the comments received and on additional investigation and analysis undertaken since the December 2008 Statement of Basis was published (including an analysis of $PM_{2.5}$ emissions as discussed above).[158] This section addresses some of the specific comments received regarding the Soils & Vegetation analysis.

1. Survey of Existing Soils & Vegetation Resources:

The Air District received several comments criticizing the inventory of existing soils and vegetation resources in the vicinity of the project. These comments criticized the use of a soils and vegetation survey conducted for the original Energy Commission proceeding in 2001, and

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[156] *See id.*
[157] *See id.* at p. 12.
[158] The Air District's Revised Soils & Vegetation analysis is included with the Memorandum from Glen Long to Weyman Lee, July 27, 2009.

claimed than an updated survey should be used. The comments stated that the soils and vegetation inventory omitted several plant species in the vicinity of the project location because of this situation. In response to these comments, the Air District has revised its inventory of soils and vegetation resources based on an updated survey of the project location. This updated inventory is outlined in the revised soils and vegetation analysis, and it now includes all plant species found in the vicinity of the proposed project. The Air District invites further public comment if any member of the public believes that there are any soils or vegetation resources that have not been included.

2. Consideration of Hayward Regional Shoreline and East Bay Hills

The Air District also received comments stating that it should evaluate the potential for soils and vegetation impacts in the Hayward Regional Shoreline and in several park areas in the East Bay hills. These comments coincided with further evaluation of the potential for endangered species impacts in these areas by EPA Region 9 and the Fish and Wildlife service. Further investigation of the potential for soils and vegetation impacts (as well as related wildlife impacts) in these areas as a result of the facility's emissions was conducted, and the Air District has included this further evaluation in its soils and vegetation analysis. The Air District invites the public to review and comment on this further analysis.

3. Endangered Species and Wildlife Issues

The Air District also received several comments criticizing the Air District's soils and vegetation analysis for failing to specifically address the potential for impacts to wildlife such as small mammals and birds. In response to these comments, the Air District wishes to clarify for the record that although potential impacts to wildlife are important resource considerations, they are addressed primarily through other regulatory mechanisms such as the Endangered Species Act and CEQA, not through the Federal PSD regulations. Looking specifically at the requirements of the Federal PSD regulations, they address only impacts to soils and vegetation. The Air District has evaluated the potential for such impacts as explained in its soils and vegetation analysis and has found that there will not be any significant soils and vegetation impacts as a result of air emissions from the facility. Soils and vegetation issues can often be related to wildlife issues because soils and vegetation provide habitat and food for wildlife, and so to the extent that there is such a connection here, the Air District's findings of no significant impact on soils and vegetation would support a finding of no significant impacts on wildlife, either. Moreover, EPA Region 9 and the US Fish and Wildlife Service are evaluating the potential for wildlife impacts in more detail, and the Air District has agreed not to take final action on this permit before those agencies can complete their consultation.

4. Nitrogen Deposition Issues

The Air District also received several comments criticizing its soils and vegetation analysis for not considering the potential for impacts from nitrogen deposition as a result of the project. These comments were based on a concern that non-native vegetation would be able to out-compete native vegetation, which is better adapted to nitrogen-poor soils, if significant additional nitrogen deposition caused those soils to become more nitrogen-rich. These comments also coincided with further evaluation of the potential for nitrogen deposition-related impacts by EPA Region 9 and the Fish & Wildlife Service. In response to these comments, a nitrogen deposition analysis was undertaken for the project, as described in more detail in the Air District's revised soils and vegetation analysis.[159] Nitrogen deposition was modeled using both the AERMIC Model (AERMOD) and CALPUFF air dispersion model. According to the Applicant's assessment, the maximum annual deposition rates calculated by AERMOD in areas potentially occupied by selected species range from 0.02 to 0.37 kilograms per hectare per year (kg/ha/yr), which is more than ten times below the levels where limited invasion of non-native species have been observed (4-5 kg/ha/yr). The maximum annual deposition rates calculated by CALPUFF are more than 100 times below such levels. These results demonstrate that nitrogen deposition from the proposed facility will not result in adverse effects on soils or vegetation resources. The modeled deposition rates reflect a number of conservative assumptions and therefore represent an over-estimation of the actual deposition expected to occur as a result of the project. Even so, the modeled impacts fall far below the levels of concern identified by earlier studies. The Air District invites further public comment on this nitrogen deposition analysis.

D. <u>"Associated Growth" And "Secondary Emissions" Analyses</u>

The Air District also received comments questioning the associated growth analysis performed as part of the AQIA. Some comments noted that there may be emissions associated with temporary and permanent workers at the site, for example through commuting. Others suggested that the new electrical generating capability provided by the facility may cause associated growth, and that the Air District should take into account the air emissions from such growth.

With respect to emissions from the workforce that will be associated with the project, the Air District addressed this issue in its Air Quality Impact Analysis prepared in connection with the December 2008 proposed permit (*see* Statement of Basis at pp. 16, 93-94). The need for workers for the project will not cause any significant associated growth because they will come from the existing workforce, which is more than adequate to meet the facility's needs. As the project will not cause any significant increase in the size of the workforce in the Bay Area, there will not be any need for any significant expansion of associated infrastructure such as housing. With respect to the new electrical generating capacity that the project will provide, it is speculative whether this new capacity will be a cause or any significant growth in the region. Some of it may be used to take the place of older generating capacity that is being taken off-line, and even if it does provide some overall expansion of the region's total electric generating capacity there is no indication that this would cause any new development. It is unlikely that any new growth or development will occur simply because of the existence of excess electrical generating capacity, as opposed to some other independent reason. For these reasons, new electrical generating capacity is not an issue that falls within the "associated growth" analysis required by EPA's PSD permitting regulations.

The District also received a comment disagreeing with the District's assertion that the project will not involve secondary growth, claiming that it already has generated secondary growth in

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[159] *See Russell City Energy Center: Nitrogen Deposition at East Bay Regional Parks*, Technical Memorandum from Craig Williams, Biologist, CH2M Hill, to Barbara McBride, Calpine, February 19, 2009.

the form of an expanded local water treatment plant the capacity of which was increased to handle cooling water for the project. This comment appears to be based on a misconception regarding the proposed facility's relationship with the City of Hayward's wastewater treatment plant. The proposed facility has been designed to handle wastewater from the treatment plant and use it as cooling water, not the other way around – the wastewater treatment plant was not built to handle wastewater from the proposed facility. This will be an environmentally beneficial aspect of the facility in that it will obviate the need for the City of Hayward to discharge its wastewater into the Bay. The project will require a new tertiary treatment plant to treat the wastewater from the wastewater treatment plant in order to make it clean enough to use in the facility's cooling system, but it will not involve any expansion to the capacity of the wastewater treatment plant. The District is unaware of any other relevant changes that have been made to the wastewater treatment plant, and in particular of any changes that may impact air quality. The Air District invites members of the public to comment further if they are aware of any increases in air emissions from any associated growth with respect to the wastewater treatment plant as a result of this project.

XII. HEALTH RISK ASSESSMENT ISSUES

The Air District also received some comments on issues related to the Health Risk Assessment it prepared for the proposed project. The Air District addresses Health Risk Assessment issues in this section.

1. Health Risk Assessment Methodology

The Air District received comments questioning the Health Risk Assessment methodology it used, and in particular whether it is appropriate for use in federal PSD Permitting. One comment also questioned why health impacts with a hazard index of less than 1 are not significant. Another comment criticized the District's methodology for assessing risk with respect to morbidity, and claimed that the District should consider mortality instead.

In response to these comments, the Air District wishes to clarify that the PSD permitting requirements do not directly require a Health Risk Assessment to be performed at all. PSD permitting does tangentially involve the District's Health Risk Assessment in areas such as the BACT comparison of alternative control technologies, which can involve an assessment of collateral environmental impacts such as toxics risk, but EPA does not specify any particular methodology for conducting such an assessment. Instead, EPA allows permitting agencies to use whatever methodology is most appropriate. The Air District uses the methodology developed by California's Office of Environmental Health Hazard Assessment ("OEHHA"), which is highly appropriate for this purpose. No commenters provided any specific information to suggest that this methodology is not appropriate for use here, or that some alternative methodology would be preferable, and the Air District is not aware of any.

With respect to why a hazard index of less than one is not significant, a hazard index below one means that the toxic exposure is less than the "Reference Exposure Level", which is a level developed by health professionals as an indicator of potential adverse health impacts. The hazard index is the sum of the individual hazard quotients for toxic air contaminants identified as affecting the same target organ or organ systems. A hazard quotient is the ratio of the estimated exposure level to the Reference Exposure Level, which is the concentration level at or below which no adverse health effects are anticipated. An exposure below the Reference Exposure Level means that no adverse health effects are anticipated for the exposure duration involved. The Hazard Index measures exposure relative to this Reference Exposure Level; a Hazard Index of less than 1 means that the exposure will be less than the Reference Exposure Level and thus protective of public health.

With respect to considering morbidity instead of mortality in assessing the level of risk, morbidity is an appropriate measure for health risk assessment purposes. Looking at morbidity is broader and more conservative in that it captures all potential health problems, not just those that are fatal. That is, morbidity encompasses all potential health effects that could arise from toxic exposures, whereas mortality encompasses only those health effects that might cause death, which is a smaller subset of exposures. The Air District therefore disagrees that the morbidity approach is inappropriate for a health risk analysis.

2. Exposure Assumptions for Non-Carcinogenic Chronic Risk

The Air District received comments stated that the chronic exposure modeling was based on the assumption that chronic exposure to toxic compounds will last one year, which they claimed is inappropriate for a power plant that will likely be in operation for a longer time period. In light of this comment, the Air District would like to clarify the record on how non-carcinogenic chronic health risks are assessed. For chronic risks, the Health Risk Assessment looks at the annual exposure rate for the maximally exposed individual, and then assumes that the individual will be exposed to this maximum annual exposure rate for the entire year over every year of an assumed 70-year life span. The Health Risk Assessment therefore appropriately captures lifetime risk; it does not assume that exposure occurs for one year and then stops.[160]

3. Health Risk Assessment for Ammonia Emissions

Commenters stated that ammonia emissions will be up to 15.2 lb/hr, which they claimed exceeds the acute trigger level of 7.1 lb/hr. The commenters claimed that the District should "thoroughly analyze potential health impacts from the ammonia emissions". The Air District would like to clarify for the record that the Health Risk Assessment did in fact take ammonia emissions into account.[161]

4. Health Risks From Legionnaire's Disease

Commenters suggested that the wet cooling system could involve a risk of causing Legionnaire's disease, and claimed that this potential health risk should be investigated further as part of the Health Risk Analysis. The Air District notes that its expertise as a public health agency is primarily in the area of chemical air pollutant and the health problems they can cause, not in medical pathogens. For this reason, the Air District does not address medical concerns such as issues related to Legionnaire's disease in its Health Risk Assessment. To the extent that the proposed project may raise concerns about Legionnaire's disease, those concerns should appropriately be addressed in the broader environmental review context through the Energy Commission's CEQA-equivalent process.

5. Health Risk Assessment for Aircraft Pilots and Passengers

Commenters claimed that the Health Risk Assessment should take into account potential health risks to pilots and passengers flying in the vicinity of the proposed facility. In response to these comments, the Air District has conducted an additional health risk assessment using an air dispersion model to determine emissions impact above ground level (*i.e.*, using a "flagpole receptor"). The maximum potential hazardous air pollutant emission rates were used. Flagpole receptor is defined where persons (pilots and passengers) may be exposed to concentrations above ground level (flight area) of a particular compound or substance. The locations are not necessarily a residence or a location where people actually exist; it may be any offsite above ground level where a person could potentially be present.

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[160] *See* Memorandum from Glen Long to Weyman Lee, February 28, 2007, at 1.
[161] *See id.*, p. 1 of attached supporting documentation showing ammonia analysis.

The proposed project will have two stacks each having a height of 150 feet above the ground level. The acute hazard index was calculated to be 0.52.[162] A value below 1.0 means that the exposure would not cause any acute adverse health effects. The location of the maximum acute hazard index is very close to the RCEC stacks and is based on one-hour exposure level. This is most likely a conservative assumption, as it is unlikely that that pilots and/or passengers would remain at this location in the airspace for a continuous hour and be exposed to the full extent assumed in the District's analysis.

6. Health Impacts of Fine Particulate Matter

The Air District received comments citing recent developments in the understanding of the health impacts of fine particulate matter. These comments suggested that the Air District should consider fine particulate matter in its Health Risk Assessment.

The District has considered adding fine particulate matter in our permitting procedures. In addition, OEHHA is planning to develop new procedures to address fine particulate matter and to incorporate them into its health risk assessment guidelines that are used by air districts. The District intends to participate in the public process to develop future updates to the risk assessment guidelines and procedures. These guidelines have not been developed at this stage, however, and so the Air District does not have the appropriate tools to include fine particulate matter in its formal Health Risk Assessment. The Air District has addressed fine particulate matter in its PSD Air Quality Impact analysis, however, as detailed above. That analysis found that emissions from the proposed facility would not have any significant contribution to any fine particulate matter pollution in violation of the stringent new National Ambient Air Quality Standards, which are health-protective standards established by EPA.

[162] *See* email memorandum from Glen Long to Bob Nishimura, March 12, 2009.

XIII. ENVIRONMENTAL JUSTICE ISSUES

The Air District received several comments regarding environmental justice issues. Commenters stated that there are areas near the proposed facility with low-income and minority residents, and claimed that the project disparately places environmental burdens on such residents. Some commenters also referenced an Environmental Justice analysis undertaken by the CEC that found that the area is "majority-minority". The Air District is aware of the CEC's analysis regarding the demographic makeup in areas near the project site. But the Air District's conclusion that there will be no disproportionate adverse impacts on any environmental justice community was not based on an assumption that there are no environmental justice communities near the project site, it was based on the District's assessment that there will be no significant adverse impacts to any community, regardless of demographic makeup. (*See* Statement of Basis, pp. 65-66.) The Air District continues to believe that there will not be any significant adverse impacts on any community regardless of demographic makeup.

The District also received comments claiming that the Air District cannot use the same Health Risk Assessment methodology it uses for other projects to assess potential impacts to Environmental Justice communities. These commenters claimed that environmental justice communities have specific attributes that make them susceptible to air pollution impacts in unique ways, such as increased susceptibility to diseases such as asthma, chronic lung disease, congestive heart failure and other chronic conditions, higher overall mortality rates, and less access to medical insurance coverage. In light of these comments, the Air District would like to clarify for the record that its Health Risk Assessment methodology is designed to take sensitive populations, such as those who may be particularly sensitive to air pollution concerns, into account.[163] This is an important consideration for all communities, as every community has some members who may have heightened sensitivity to potential airborne health hazards to some extent. The Air District supports its Health Risk Assessment methodology as an appropriate way to characterize the potential health risks associated with the proposed Russell City Energy Center with respect to communities that have members with heightened environmental sensitivities.

The Air District also received comments asserting that the District should also have examined the "synergistic effects" of existing pollution sources in the area. These comments asserted that the District should analyze the cumulative impacts of the emissions from the Russell City project in conjunction with existing sources in the area. The Air District's Health Risk Assessment methodology does not include an assessment of cumulative risk from project plus existing background sources for several reasons. First, where level of risk from a project is found to be

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[163] OEHHA's methodology for deriving health effects values (CPFs and RELs) are protective of public health and account for potential exposure to sensitive populations. In accordance with OEHHA, the concentration, at or below which no adverse health effects are anticipated in the general human population, is termed the reference exposure level (REL). RELs are based on the most sensitive relevant adverse health effect reported in the medical and toxicological literature. RELs are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. CPFs (cancer potency factors), developed by OEHHA, are based on the use of the linearized 95% upper confidence interval of risk as a dose-response assessment, which is considered protective of public health.

so low that it is below the HRA significance thresholds, the project is not expected to make more than a *de minimis* contribution to any cumulative risk. Assessing the facility's addition to the overall cumulative risk burden would therefore add relatively little to the understanding of the cumulative concern. Moreover, undertaking a risk assessment encompassing all emission sources in the region of the facility would require resources that do not exist at this time. There are significant technical difficulties associated with completing a neighborhood-scale cumulative HRA, which are largely related to incompleteness of data (*e.g.*, spatial and temporal emission patterns) needed to estimate exposures and health risks, and to ascertain source contributions. Furthermore, unlike for criteria air pollutants, no standards have been established for health risks associated with cumulative exposure to TACs emitted from all sources, and so it would be difficult to assess at what level additional cumulative impacts would become significant. And finally, cumulative environmental impacts must be assessed for any project in California under CEQA, and so to the extent that cumulative toxic risks have the potential to be significant they can be addressed in that context. For all of these reasons, the Air District does not currently conduct an evaluation of a project's addition to cumulative health risk in its Health Risk Assessment process. But the District certainly does share the commenters' concerns about issues surrounding siting new projects in locations where there is already an elevated background level of toxic air contaminants. The Air District has recently issued a proposal to establish more stringent air permitting requirements for toxic air contaminants as a measure to address cumulative air pollution in more highly impacted communities. This proposal, if adopted, would represent the most stringent air permitting requirements for TACs in the country, as far as District staff are aware. The approach involves reducing the allowable project risk thresholds by a factor of two for projects located within more highly impacted communities. The maximum project risks for Russell City Energy Center are much less than these proposed more stringent project health risk standards.

Finally, the Air District received comments asserted that the District should have conducted a broader public outreach regarding environmental justice concerns. The Air District believes that it has conducted a very robust level of public outreach regarding all aspects of this project, including environmental justice issues. The Air District widely publicized its proposal to issue the Federal PSD permit in the community, and held a public hearing at Hayward City Hall to allow residents to express their views on the proposal. Notably, the Air District went well beyond what is required by the Federal PSD regulations in providing notice to Spanish-speaking populations and in providing a translation service at the public hearing to ensure the broadest possible opportunity for public participation.

PROPOSED PSD PERMIT CONDITIONS

The Air District is proposing the following permit conditions to ensure that the proposed project will comply with all applicable Federal PSD requirements. Compliance with emissions limits will be verified by continuous emission monitors and/or periodic source tests. The proposed facility will be required to maintain records of emissions and report them to the Air District for compliance purposes.

The Air District developed the following list of proposed permit conditions as part of its integrated permit review process covering both Federal PSD and state law requirements. As such, the entire list contains some conditions required by the Federal PSD Regulation and some conditions required under state law. In some instances a permit condition may be required under both the Federal PSD Regulation and state law, for example with certain Best Available Control Technology requirements where federal and state law overlap. The requirements of the Federal PSD Regulation are those discussed in the previous sections of this document, and the proposed conditions that are being implemented pursuant to the Federal PSD Regulation are the conditions necessary to ensure compliance with the requirements discussed above. To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in "strike-through" format below. For a full understanding of what permit conditions are required by the Federal PSD Regulation, the reader should consult the detailed analyses of Federal PSD requirements set forth in the previous sections of this document and in the initial Statement of Basis published in December of 2008; the Federal PSD Regulation itself; relevant decisions of the Environmental Appeals Board; and other related authorities. Permit conditions that are not being proposed pursuant the Federal PSD Regulation are not part of this proposed permitting action; persons interested in any such conditions will need to take up their concerns in the appropriate state law forum (to the extent one is available at this stage).[164]

The Air District is also providing citations to relevant authorities following certain conditions to help the reader understand the legal authority under which the Air District is proposing the condition. These citations are intended as reader aids only, and should not be considered the Air District's definitive analysis of the legal authorities underlying each condition. In particular, many conditions may be authorized by or otherwise implicate multiple legal authorities, some of which may not be listed for each condition. For a complete discussion of what permit requirements are being imposed pursuant to the Federal PSD Regulation, the reader should refer to the relevant discussions in previous sections of this document in the initial Statement of Basis published in December of 2008.

The readers should also note that the proposed conditions below constitute revisions from the conditions as initially proposed in December of 2008, in accordance with the Air District's additional and revised analysis set forth above. For the convenience of members of the public who have been following this permitting proceeding and are familiar with the December 2008

[164] As noted in the December 2008 Statement of Basis, the state-law permitting process has been completed and is now final. Avenues for reviewing state-law conditions have therefore been exhausted.

proposed conditions, a comparison of the December 2008 proposed conditions and the current proposed conditions is presented in "track changes" format in Appendix B.

Russell City Energy Center
Proposed 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
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 19(b) and 19(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 19(b) and 19(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(b) through 19(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 performed, 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
CO_2E:	Combined emissions of CO_2, CH_4, and N_2O, expressed in terms of the amount of CO_2 emissions that would have the equivalent impact on global climate change.

(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. Conditions 50 through 61 shall apply at all times.

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 $PM_{2.5}$, 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~~	
$PM_{2.5}$/PM_{10}	413 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}/ $PM_{2.5}$)
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}/ $PM_{2.5}$)
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 10 pounds per hour or 0.0045 lb/MM BTU of natural gas fired, averaged over any 1-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at 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 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} and $PM_{2.5}$) mass emissions at P-1 & P-2 each shall not exceed 7.5 pounds per hour or 0.0036 lb PM_{10}/ $PM_{2.5}$ per MM BTU of natural gas fired. (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	Hot Start-Up	Warm Start-Up	Shutdown
	lb/start-up	lb/start-up	lb/start-up	lb/shutdown
NO_x (as NO_2)	480.0	95	125	40
CO	2514	891	2514	100
~~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) 1,453 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) 7,360 pounds of CO per day (PSD)
   ~~(d) 295 pounds of POC (as CH_4) per day (Cumulative Emissions)~~
   (e) 413 pounds of PM_{10} and $PM_{2.5}$ 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) 127 tons of NO_x (as NO_2) per year (Offsets, PSD)
   (b) 330 tons of CO per year (Cumulative Increase, PSD)
   ~~(c) 28.5 tons of POC (as CH_4) per year (Offsets)~~
   (d) 71.8 tons of PM_{10} and $PM_{2.5}$ 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.
    (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..
    (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} and $PM_{2.5}$) 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 $PM_{2.5}$~~, 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 $PM_{2.5}$~~, 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} and $PM_{2.5}$) 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} and $PM_{2.5}$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. Permit Conditions for Cooling Towers

44. 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 6,200 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)

45. 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} and $PM_{2.5}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. 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 (PSD)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. 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)

47. 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 (e)(2)(A)(3) or (e)(2)(B)(3))

48. 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)

49. 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)

E. Greenhouse Gas PSD Permit Conditions.

The following conditions shall apply at all times, and are based on the owner/operator's agreement to be subject to enforceable BACT permit limits for greenhouse gas emissions as a condition for receiving a Federal PSD Permit.

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

50. The owner/operator shall not emit more than 242 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per hour. (Basis: Voluntary Greenhouse Gas BACT Requirement)

51. The owner/operator shall not emit more than 5,802 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per day. (Basis: Voluntary Greenhouse Gas BACT Requirement)

52. The owner/operator shall not emit more than 1,928,182 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per year. (Basis: Voluntary Greenhouse Gas BACT Requirement)

53. The owner/operator shall maintain the S-1 & S-3 Gas Turbines such that the heat rate of each turbine does not exceed 7,730 Btu/kWhr. (Basis: Voluntary Greenhouse Gas BACT Requirement)

54. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Hourly, daily, and annual heat input.
    b. Hourly, daily, and annual greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the hourly, daily, and annual heat input by an emissions factor of 119.0 pounds of CO_2E per MMBtu of heat input.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

55. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved heat rate performance test on exhaust points P-1 and P-2 while each Gas Turbine is operating at maximum load to determine compliance with Condition 54. The owner/operator shall conduct this heat rate performance test according to the requirements of the American Society of Mechanical Engineers Performance Test Code

on Overall Plant Performance, ASME PTC 46-1996. (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-6 Fire Pump Diesel Engine

56. The owner/operator shall not emit more than 7.6 metric tons CO_2E from the S-6 Fire Pump Diesel Engine per rolling 12-month period during operation subject to Condition 46. (Basis: Voluntary Greenhouse Gas BACT Requirement)
57. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing fuel meter for the engine is installed, operated and properly maintained. (Basis: Voluntary Greenhouse Gas BACT Requirement)
58. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Monthly fuel usage.
    b. Monthly greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the amount of fuel used per month by an emissions factor of 21.7 pounds of CO_2E per gallon of fuel used.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-7 through S-11 Circuit Breakers

59. The owner/operator shall not emit more than 39.3 metric tons of CO_2E from the S-S-7 through S-11 circuit breakers per rolling 12-month period. (Basis: Voluntary Greenhouse Gas BACT Requirement)

60. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Amount of dielectric fluid added to the circuit breakers for each month of facility operation.
    b. Greenhouse gas emissions from the circuit breakers for each month of facility operation, expressed in metric tons of CO_2E and calculated by multiplying the amount of dielectric fluid added by an emissions factor of 10.84 metric tons of CO_2E per pound of dielectric fluid added during the month.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

61. The owner/operator shall install and maintain a leak detection system on the circuit breakers that signals an alarm in the facility's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly respond to any alarm, investigate the circuit breaker involved, and fix any leak-tightness problems that caused the alarm. (Basis: Voluntary Greenhouse Gas BACT Requirement)

PROPOSED FEDERAL PSD PERMIT DECISION

The Air District's Air Pollution Control Officer ("APCO") has concluded that the proposed Russell City Energy Center power plant, which is composed of the permitted sources listed below, will comply with all applicable Federal PSD Permit requirements. The APCO is therefore proposing to issue a Federal PSD Permit for the Russell City Energy Center as set forth in the December 8, 2008, Statement of Basis, and as revised and updated in this Additional Statement of Basis. The following sources will be subject to the proposed permit conditions 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.
S-7 Circuit Breaker
S-8 Circuit Breaker
S-9 Circuit Breaker
S-10 Circuit Breaker
S-11 Circuit Breaker

Pursuant to the requirements of 40 C.F.R. Part 124, the Air District's revised proposal to issue a Federal PSD Permit for this project is subject to public notice and an opportunity for interested members of the public to review and comment on it. Information on how the public can participate in and comment on this revised proposed decision is provided in the opening pages of this document, and is also being provided to the public by formal legal notice.

APPENDIX A

Proposed Federal PSD Permit for the Russell City Energy Center
Additional Statement of Basis, August 3, 2009

SDG&E – Palomar Energy Center
Summary of Emissions of NOx During Startup Events
After Installation of OpFlex

2006 based upon minute-by-minute NOx data; 2007 as provided by SDG&E

	Date	Start Time	Compliance Time	Total Time	Total Nox lbs	Hours since shutdown
CT1	10/11/2006	7:15	11:58	4:43	735	4 days
	10/12/2006	2:16	4:04	1:48	248	5 hours
	10/13/2006	6:05	7:36	1:31	42	5.5 hours
	16-Oct	6:44	8:03	1:19	107	2 days 13 hours
	17-Oct	6:02	7:00	0:58	48	7 hours
	18-Oct	6:02	6:54	0:52	39	6.5 hours
	11/4/2006	12:24	13:20	0:56	37	2 hours
	11/11/2006	7:03	7:41	0:38	26	6 hours
	11/12/2006	5:39	6:32	0:53	32	5.5 hours
	11/13/2006	6:00	6:54	0:54	34	7 hours
	11/14/2006	4:59	5:49	0:50	32	5 hours
	11/17/2006	4:59	5:55	0:56	28	5 hours
	19-Nov	7:01	7:39	0:38	30	7 hours
	11/26/2006	7:16	8:19	1:03	88	3 days; hot steam turbine
	12/10/2006	8:14	8:37	0:23	22	8 hours
	12/24/2006	6:14	6:38	0:24	24	6 hours
	12/25/2006	8:14	8:43	0:29	31	8 hours

	Date	Start Time	Compliance Time	Total Time	Total Nox lbs	Hours since shutdown
CT1	11/27/2006	10:13	10:41	0:28	28	10 hours
	12/28/2006	9:12	9:40	0:28	23	9 hours
	12/31/2006	7:14	7:39	0:25	23	7 hours
	5/1/2007	9:00	10:51	1:51	145	Regular (Questionable)
	10/22/2007	11:59	13:31	1:32	225	Cold CT; hot ST
CT2	10/12/2006	4:27	6:48	2:21	460	>48 hours
	10/12/2006	12:10	12:33	0:23	12	2 hours
	11/4/2006	13:38	14:10	0:32	17	4 hours
	11/5/2006	7:02	7:55	0:53	39	7 hours
	11/6/2006	5:02	5:47	0:45	39	5 hours
	11/18/2006	6:38	7:35	0:57	40	6.5 hours
	11/23/2006	6:05	6:25	0:20	16	6 hours
	11/27/2006	7:00	7:30	0:30	75	7 hours
	12/11/2006	5:11	5:27	0:16	19	4 hours
	12/23/2006	14:55	15:52	0:57	111	38 hours
	12/29/2006	15:14	15:53	0:39	50	15 hours
	12/30/2006	15:15	15:48	0:33	31	14 hours
	5/7/2007	7:11	8:53	1:42	119	Cold CT; hot ST
	10/22/2007	6:29	11:26	4:57	375	Cold CT; cold ST

APPENDIX B

Proposed Federal PSD Permit for the Russell City Energy Center
Additional Statement of Basis, August 3, 2009

PROPOSED PERMIT CONDITIONS COMPARED TO PERMIT CONDITIONS AS PROPOSED IN DECEMBER, 2008

For ease of reference by members of the public who reviewed the Air District's proposed permit conditions published in December of 2008, set forth below are the current proposed conditions with the revisions from the December 2008 proposal indicated in a "track changes" format. Deleted material is indicated in the margin and inserted material is underscored.

Russell City Energy Center Proposed 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
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 19(b) and 19(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 19(b) and 19(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the

Deleted: Rolling 3-hour period: Any consecutive three-hour period, not including start-up or shutdown periods

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termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(b) through 19(d) until termination of fuel flow to the Gas Turbine

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Gas Turbine Combustor Tuning Mode:	The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are performed, 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
CO_2E:	Combined emissions of CO_2, CH_4, and N_2O, expressed in terms of the amount of CO_2 emissions that would have the equivalent impact on global climate change.

(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. Conditions 50 through 61 shall apply at all times.

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 $PM_{2.5}$, 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~~	
$PM_{2.5}$/PM_{10}	413 pounds per calendar day	
~~SO_2~~	~~298 pounds per calendar day~~	

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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.

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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}/ $PM_{2.5}$)

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}/ $PM_{2.5}$)
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 10 pounds per hour or 0.0045 lb/MM BTU of natural gas fired, averaged over any 1-hour period. (PSD for CO)

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(d) The carbon monoxide emission concentration at 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 CO)

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~~(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} and $PM_{2.5}$) mass emissions at P-1 & P-2 each shall not exceed 7.5 pounds per hour or 0.0036 lb PM_{10}/ $PM_{2.5}$ per MM BTU of natural gas fired. (BACT)

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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	Hot Start-Up	Warm Start-Up	Shutdown
	lb/start-up	lb/start-up	lb/start-up	lb/shutdown
NO_x (as NO_2)	480.0	95	125	40
CO	2514	891	2514	100
~~POC (as CH_4)~~	~~83~~	~~35.3~~	~~79~~	~~16~~

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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) 1,453 pounds of NO_x (as NO_2) per day (Cumulative Emissions)

(b) 1,225 pounds of NO_x per day during ozone

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season from June 1 to September 30. (CEC Condition of Certification)

(c) 7,360 pounds of CO per day (PSD)

~~(d) 295 pounds of POC (as CH_4) per day (Cumulative Emissions)~~

(e) 413 pounds of PM_{10} and $PM_{2.5}$ per day (PSD)

~~(f) 292 pounds of SO_2 per day (BACT)~~

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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) 127 tons of NO_x (as NO_2) per year (Offsets, PSD)

(b) 330 tons of CO per year (Cumulative Increase, PSD)

~~(c) 28.5 tons of POC (as CH_4) per year (Offsets)~~

(d) 71.8 tons of PM_{10} and $PM_{2.5}$ per year (Cumulative Increase, PSD)

~~(e) 12.2 tons of SO_2 per year (Cumulative Increase, PSD)~~

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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.

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   (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.

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   (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} and $PM_{2.5}$) 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 $PM_{2.5}$~~, 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 $PM_{2.5}$~~, 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} and $PM_{2.5}$) 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} and $PM_{2.5}$ 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. Permit Conditions for Cooling Towers

44. 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 6,200 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)

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45. 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} and $PM_{2.5}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. 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 (PSD)

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D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. 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)

47. 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 (e)(2)(A)(3) or (e)(2)(B)(3))

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48. 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)

49. 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)

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E. Greenhouse Gas PSD Permit Conditions.

The following conditions shall apply at all times, and are based on the owner/operator's agreement to be subject to enforceable BACT permit limits for greenhouse gas emissions as a condition for receiving a Federal PSD Permit.

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

50. The owner/operator shall not emit more than 242 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per hour. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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51. The owner/operator shall not emit more than 5,802 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per day. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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52. The owner/operator shall not emit more than 1,928,182 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per year. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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53. The owner/operator shall maintain the S-1 & S-3 Gas Turbines such that the heat rate of each turbine does not exceed 7,730 Btu/kWhr. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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54. 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 each circuit breaker's location, and made immediately available to the District staff upon request.

a. Hourly, daily, and annual heat input.

b. Hourly, daily, and annual greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the hourly, daily, and annual heat input by an emissions factor of 119.0 pounds of CO_2E per MMBtu of heat input.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

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55. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved heat rate performance test on exhaust points P-1 and P-2 while each Gas Turbine is operating at maximum load to determine compliance with Condition 54. The owner/operator shall conduct this heat rate performance test according to the requirements of the American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 46-1996. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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Conditions for S-6 Fire Pump Diesel Engine

56. The owner/operator shall not emit more than 7.6 metric tons CO_2E from the S-6 Fire Pump Diesel Engine per rolling 12-month period during operation subject to Condition 46. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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57. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing fuel meter for the engine is installed, operated and properly maintained. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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58. 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 each circuit breaker's location, and made immediately available to the District staff upon request.

a. Monthly fuel usage.

b. Monthly greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the amount of fuel used per month by an emissions factor of 21.7 pounds of CO_2E per gallon of fuel used.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

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Conditions for S-7 through S-11 Circuit Breakers

59. The owner/operator shall not emit more than 39.3 metric tons of CO_2E from the S-S-7 through S-11 circuit breakers per rolling 12-month period. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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60. 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 each circuit breaker's location, and made immediately available to the District staff upon request.

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a. Amount of dielectric fluid added to the circuit breakers for each month of facility operation.
b. Greenhouse gas emissions from the circuit breakers for each month of facility operation, expressed in metric tons of CO_2E and calculated by multiplying the amount of dielectric fluid added by an emissions factor of 10.84 metric tons of CO_2E per pound of dielectric fluid added during the month.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

61. The owner/operator shall install and maintain a leak detection system on the circuit breakers that signals an alarm in the facility's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly respond to any alarm, investigate the circuit breaker involved, and fix any leak-tightness problems that caused the alarm. (Basis: Voluntary Greenhouse Gas BACT Requirement)

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Exhibit 4

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
ISSUED PURSUANT TO THE
REQUIREMENTS OF 40 CFR § 52.21

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

PSD PERMIT NUMBER:	Permit Application No. 15487
PERMITTEE:	Russell City Energy Company, LLC 717 Texas Avenue, Suite 1000 Houston, TX 77002
FACILITY NAME:	Russell City Energy Center
FACILITY LOCATION:	3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in the City of Hayward, Alameda County, California

Pursuant to the provisions of Subchapter I, Part C, of the Clean Air Act (42 U.S.C. Section 7470, *et seq*.), Title 40, Section 52.21, of the Code of Federal Regulations (CFR), and the Delegation Agreement between Region IX of the Environmental Protection Agency and the Bay Area Air Quality Management District (District), the District is issuing a Prevention of Significant Deterioration (PSD) air quality permit to the Russell City Energy Company, LLC. The Permit applies to the construction and operation of a new 600 megawatt natural gas fired combined cycle power plant called Russell City Energy Center in the City of Hayward, Alameda County, California.

Russell City Energy Company, LLC, is authorized to construct and operate the power plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR Section 52.21, and the terms and conditions set forth in this PSD Permit. Failure to comply with any condition or term set forth in this PSD Permit may be subject to enforcement action pursuant to Section 113 of the Clean Air Act. This PSD permit does not relieve Russell City Energy Company, LLC, of the obligation to comply with applicable federal, state, and District air pollution control rules and regulations.

Pursuant to 40 CFR Section 124.15(b), this PSD Permit becomes effective March 22, 2010, unless a Petition for Review (appeal) is filed with EPA's Environmental Appeals Board (EAB) by that date period pursuant to 40 CFR Section 124.19. If a Petition for Review is filed, the PSD Permit does not become effective until the Petition for Review is resolved.

The District held two public comment periods on its proposal to issue this PSD Permit, including two public hearings. The Air District is publishing responses to all comments received during these comment periods concurrently with issuance of the permit. Pursuant to 40 CFR Section 124.19, any person who filed comments on the draft permit or participated in a public hearing during either public comment period may appeal the permit by filing a Petition for Review with the EAB to review any condition of the permit decision. Any person who failed to file comments or to participate in a public hearing may file a Petition for Review with the EAB to review changes that the District has made from the draft permit to the final permit. Petitions for Review must be received by the EAB no later than March 22, 2010. The EAB's mailing address is:

U.S. Environmental Protection Agency
Environmental Appeals Board
c/o Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

Further information on filing Petitions for Review can be obtained from the EAB at the above address, by telephone at (202) 233-0122, and on the internet at www.epa.gov/eab/.

As provided in 40 CFR Section 52.21(r), this PSD Permit shall become invalid if construction:

A. is not commenced (as defined in 40 CFR Section 52.21(b)(9)) within 18 months after the approval becomes effective; or
B. is discontinued for a period of 18 months or more; or
C. is not completed within a reasonable time.

Jack P. Broadbent
Executive Officer/Air Pollution Control Officer

2/13/10
Date

Russell City Energy Center
Equipment Description

S-1 Combustion Turbine Generator (CTG) #1, Siemens/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, Siemens/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.

S-7 Circuit Breaker, Alstom Type HGF

S-8 Circuit Breaker, Alstom Type HGF

S-9 Circuit Breaker, Alstom Type HGF

S-10 Circuit Breaker, Alstom Type HGF

S-11 Circuit Breaker, Alstom Type HGF

Russell City Energy Center
PSD Permit Conditions

The permit conditions set forth below in plain type are the conditions of the federal Prevention of Significant Deterioration ("PSD") Permit issued by the Bay Area Air Quality Management District ("District") for the Russell City Energy Center pursuant to 40 C.F.R. section 52.21 and the Delegation Agreement between the District and Region 9 of the United States Environmental Protection Agency. Conditions set forth in ~~strikethrough~~ type are not conditions of the PSD permit. These conditions are conditions of the related District Authority to Construct issued for the facility. They are set forth here only for convenience in comparing the two permits and are not part of the PSD permit.

(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
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 19(b) and 19(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 19(b) and 19(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(b) through 19(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 performed, 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
CO_2E:	Combined emissions of CO_2, CH_4, and N_2O, expressed in terms of the amount of CO_2 emissions that would have the equivalent impact on global climate change.

(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. Conditions 50 through 61 shall apply at all times.

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 $PM_{2.5}$, 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~~	
$PM_{2.5}/PM_{10}$	413 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}/ $PM_{2.5}$)

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}/ $PM_{2.5}$)
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 10 pounds per hour or 0.0045 lb/MM BTU of natural gas fired, averaged over any 1-hour period. (PSD for CO)
    (d) The carbon monoxide emission concentration at 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 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} and $PM_{2.5}$) mass emissions at P-1 & P-2 each shall not exceed 7.5 pounds per hour or 0.0036 lb PM_{10}/ $PM_{2.5}$ per MM BTU of natural gas fired. (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 do not exceed the limits established below. The owner/operator shall not operate both of the Gas Turbines (S-1 & S-3) in Startup Mode at the same time. (PSD, CEC Conditions of Certification)

Pollutant	**Cold Start-Up Combustor Tuning**	**Hot Start-Up**	**Warm Start-Up**	**Shutdown**
	lb/start-up	**lb/start-up**	**lb/start-up**	**lb/shutdown**
NO_x (as NO_2)	480.0	95	125	40
CO	2514	891	2514	100
~~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) 1,453 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) 7,360 pounds of CO per day (PSD)

~~(d) 295 pounds of POC (as CH_4) per day (Cumulative Emissions)~~

(e) 413 pounds of PM_{10} and $PM_{2.5}$ 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) 127 tons of NO_x (as NO_2) per year (Offsets, PSD)
(b) 330 tons of CO per year (Cumulative Increase, PSD)
~~(c) 28.5 tons of POC (as CH_4) per year (Offsets)~~
(d) 71.8 tons of PM_{10} and $PM_{2.5}$ 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.

(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.

(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} and $PM_{2.5}$) 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 $PM_{2.5}$~~, 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 $PM_{2.5}$~~, 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} and $PM_{2.5}$) 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} and $PM_{2.5}$ 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 34. 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. Permit Conditions for Cooling Towers

44. 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 6,200 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)

45. 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} and $PM_{2.5}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. 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 (PSD)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. 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)

47. 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 (e)(2)(A)(3) or (e)(2)(B)(3))

48. 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)

49. 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)

E. Greenhouse Gas PSD Permit Conditions.

The following conditions shall apply at all times, and are based on the owner/operator's agreement to be subject to enforceable BACT permit limits for greenhouse gas emissions as a condition for receiving a Federal PSD Permit.

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

50. The owner/operator shall not emit more than 242 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per hour. (Basis: Voluntary Greenhouse Gas BACT Requirement)

51. The owner/operator shall not emit more than 5,802 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per day. (Basis: Voluntary Greenhouse Gas BACT Requirement)

52. The owner/operator shall not emit more than 1,928,182 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per year. (Basis: Voluntary Greenhouse Gas BACT Requirement)

53. The owner/operator shall maintain the S-1 & S-3 Gas Turbines such that the heat rate of each turbine does not exceed 7,730 Btu/kWhr. (Basis: Voluntary Greenhouse Gas BACT Requirement)

54. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Hourly, daily, and annual heat input.

b. Hourly, daily, and annual greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the hourly, daily, and annual heat input by an emissions factor of 119.0 pounds of CO_2E per MMBtu of heat input.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

55. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved heat rate performance test on exhaust points P-1 and P-2 while each Gas Turbine is operating at maximum load to determine compliance with Condition 53. The owner/operator shall conduct this heat rate performance test according to the requirements of the American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 46-1996. (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-6 Fire Pump Diesel Engine

56. The owner/operator shall not emit more than 7.6 metric tons CO_2E from the S-6 Fire Pump Diesel Engine per rolling 12-month period during operation subject to Condition 46. (Basis: Voluntary Greenhouse Gas BACT Requirement)
57. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing fuel meter for the engine is installed, operated and properly maintained. (Basis: Voluntary Greenhouse Gas BACT Requirement)
58. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Monthly fuel usage.
    b. Monthly greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the amount of fuel used per month by an emissions factor of 21.7 pounds of CO_2E per gallon of fuel used.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-7 through S-11 Circuit Breakers

59. The owner/operator shall not emit more than 39.3 metric tons of CO_2E from the S-S-7 through S-11 circuit breakers per rolling 12-month period. (Basis: Voluntary Greenhouse Gas BACT Requirement)

60. 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 each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Amount of dielectric fluid added to the circuit breakers for each month of facility operation.
    b. Greenhouse gas emissions from the circuit breakers for each month of facility operation, expressed in metric tons of CO_2E and calculated by multiplying the

amount of dielectric fluid added by an emissions factor of 10.84 metric tons of CO_2E per pound of dielectric fluid added during the month.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

61. The owner/operator shall install and maintain a leak detection system on the circuit breakers that signals an alarm in the facility's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly respond to any alarm, investigate the circuit breaker involved, and fix any leak-tightness problems that caused the alarm. (Basis: Voluntary Greenhouse Gas BACT Requirement)

Exhibit 5

Responses to Public Comments

Federal “Prevention of Significant Deterioration” Permit

Russell City Energy Center

Bay Area Air Quality Management District
Application Number 15487

February 2010

Responses to Public Comments on
Draft Federal Prevention of Significant Deterioration Permit
Russell City Energy Center

The Bay Area Air Quality Management District ("Air District") is issuing a Federal Prevention of Significant Deterioration ("PSD") permit to the Russell City Energy Company, LLC, for construction and operation of the Russell City Energy Center. The Air District is issuing this Federal PSD Permit in accordance with the requirements of 40 C.F.R. Section 52.21 and 40 C.F.R. Part 124, and under authority to issue PSD Permits delegated by EPA Region IX. This document sets forth the Air District's responses to the public comments it received on this permit.

The Federal PSD Permit that the Air District is issuing for this facility is based on the analysis and conclusions set forth in the Air District's December 8, 2008, Statement of Basis and August 3, 2009, Additional Statement of Basis, as well as on the Responses to Comments set forth in this document. These documents, as well as all of the supporting documentation on which the Air District's permitting analysis is based, are available for public review at Air District headquarters at 939 Ellis Street, San Francisco, CA, 94117. The most significant documents are also available electronically on the Air District's website at www.baaqmd.gov.

Members of the public who participated in this permitting action and who are dissatisfied with the District's permitting action may appeal the permit to the Environmental Appeals Board ("EAB") pursuant to the appeal provisions of 40 C.F.R. Section 124.19. Any such members of the public must file any appeal no later than March 22, 2010. Permit appeals must be actually received and filed with the Environmental Appeals Board no later than March 22, 2010, to be considered timely. More information regarding the EAB appeals process is available from the EAB at the following address:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
www.epa.gov/eab/

Notice of this permitting action will be served by U.S. mail and/or e-mail on the permit applicant, all persons who submitted written or oral comments during the public comment periods for this permit, and other interested persons and entities. Although not required for PSD permits, notice will also be provided by publication in at least one newspaper of general circulation in the area where the project is located, in keeping with the Air District's practice under state-law rules for issuing Authority to Construct permits.

Dated: February 3, 2010

Jack P. Broadbent
Executive Officer/Air Pollution Control Officer

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I. INTRODUCTION AND SUMMARY OF CHANGES MADE IN FINAL PERMIT

The Air District is issuing a Federal Prevention of Significant Deterioration ("PSD") permit to Russell City Energy Company, LLC, for construction and operation of the Russell City Energy Center. The Russell City Energy Center will be a nominal 600-MW natural gas fired combined-cycle power plant located at 3862 Depot Road in Hayward, CA, near the corner of Depot Road and Cabot Boulevard.

The Air District is issuing this Federal PSD Permit after a comprehensive permitting review to ensure that the facility will comply with all requirements of the Federal PSD program under the Clean Air Act. The Air District summarized its analysis of the facility and how it will comply with applicable Federal PSD requirements in the Statement of Basis for this project, which the Air District published on December 8, 2008, along with its initial proposal to issue this permit. The Air District solicited public comment on the December 2008 Draft PSD Permit and accompanying Statement of Basis, and accepted written comments until February 6, 2009. The Air District also held a public hearing at Hayward City Hall to receive comments in person on January 21, 2009. Based on the comments received during this first comment period, as well as on additional review and analysis by Air District staff, the District revised its proposal. The Air District published a revised Draft PSD Permit on August 3, 2009, along with an Additional Statement of Basis summarizing the Air District's analysis on which the revised draft permit was based. The Air District then held a second public comment period on the revised Draft PSD Permit, and accepted written comment until September 16, 2009. The Air District also held a second public hearing at Hayward City Hall on September 2, 2009.

The Air District has carefully considered all of the comments it received during both public comment periods. The Air District is now issuing a final Federal PSD Permit based on the District's analysis and on the public comments it has received. The Air District's responses to the public comments it received, during both comment periods, are set forth in this document pursuant to the requirements of 40 C.F.R. Section 124.17. Section 124.17 requires that the Air District respond to significant comments received during the public comment periods. The Air District is going beyond this minimum requirement, however, and is also responding to certain comments that are not relevant to any Federal PSD permit issues as well as certain communications on this permit that were not received during the two public comment periods. The Air District is providing these additional responses out of recognition of the public's interest in these issues and in order to provide the public with as much information as possible regarding this project.

Based on the Air District's review of the public comments, as well as on its own further analysis, the Air District is making the following changes from the draft permit it published, which are reflected in the Final Permit. These changes are outlined here in summary form, and are discussed in greater detail in the relevant sections of this document.

- **Carbon Monoxide Emissions Limits:** The Air District has lowered the emissions limit on carbon monoxide from 4.0 parts per million volume on a dry basis (ppmvd), corrected to 15% oxygen averaged over any rolling 3-hour period, to 2.0 ppmvd corrected to 15% oxygen, averaged over a 1-hour period. (*See* Condition 19(d).) This change was made in response to public comments suggesting that lower levels than 4.0 ppmvd are achievable for this facility. Carbon monoxide issues are discussed in Section V of this Response to Comments document.

- **Particulate Matter Emissions:** The Air District has lowered the emissions limit on particulate matter from the gas turbines and heat recovery boilers from 9 pounds per hour to 7.5 pounds per hour. (*See* Condition 19(h).) The Air District has also lowered the particulate-matter-related limit on total dissolved solids in the facility's cooling water from 8,000 ppm to 6,200 ppm, which will reduce the particulate matter emissions from the cooling tower. (*See* Condition 44.) The Air District made these changes based on further review and analysis of available data on what level of emissions control is achievable for this facility. The Air District is also clarifying that the particulate matter limits will apply both to PM_{10} and to $PM_{2.5}$, which is a subset of PM_{10} that has recently come under heightened regulatory scrutiny. Particulate matter issues are discussed in Section VI of this Response to Comments document.

- **Startup Emissions Limits:** The Air District has lowered several of the emissions limits applicable during turbine startups. The District has lowered the limit on emissions of nitrogen dioxide (NO_2) during "hot" startups – when a turbine is started up after less than eight hours of downtime – from 125 pounds per startup to 95 pounds per startup. The District has also lowered the limit on emissions of carbon monoxide during startups in two areas. For hot startups, the District has lowered the carbon monoxide limit from 2514 pounds per startup to 891 pounds per startup; and for cold startups – when a turbine is started up after more than 48 hours – the District has lowered the carbon monoxide limit from 5028 pounds to 2514 pounds. (*See* Condition 20.) These changes were made based on comments suggesting that lower limits than the Air District initially proposed would be achievable for this facility, based on the experiences of other similar facilities. The Air District is also imposing a requirement that both turbines cannot be in startup mode at the same time, which is a condition of the California Energy Commission's license for the facility but was inadvertently left out of the proposed PSD permit. Startup and shutdown issues are discussed in Section VIII of this Response to Comments document.

- **Voluntary Limits on Greenhouse Gas Emissions:** The Air District has also imposed additional and more stringent limits on the emissions of greenhouse gas pollutants, including carbon dioxide, nitrous oxide and methane, based on the applicant's voluntary request to include such limits. Greenhouse gases are not currently regulated by EPA and are not covered by any Federal PSD regulatory requirements at this time, but the applicant has nonetheless requested that the Air District undertake a BACT analysis for greenhouse gases and impose enforceable greenhouse gas limits in the permit. Based on the applicant's voluntary request, the Air District is imposing limits on hourly, daily and annual emissions of CO_2-equivalent greenhouse gases ("CO_2e"). The Air District is also imposing a limit on the facility's heat rate per unit of power output, which is related to its energy efficiency. Ensuring that the facility's heat rate is kept within the applicable limit will ensure that it is being maintained at a high level of efficiency, which will reduce greenhouse gas emissions per unit of power generated. The Air District is also imposing greenhouse gas emission limits on the emergency diesel firepump engine and the facility's circuit breakers, as well as appropriate monitoring requirements to ensure compliance with these limits. (*See* Conditions 50-61.) Greenhouse gas issues are discussed in Section II of this Response to Comments document.

- **Further Refinement of Supporting Analyses:** The Air District has also conducted further analysis in a number of areas to ensure that the facility will satisfy all Federal PSD permitting requirements. While not directly resulting in changed permit conditions, these additional analyses help strengthen this permit and are described in the appropriate sections below. The additional analyses are addressed in various places throughout this Response to Comments document.

- **Formatting and Typographical Corrections:** The District has also made minor, non-substantive corrections to correct formatting and typographical errors contained in the draft permit it published. These changes do not affect the substance of the permit.

II. ISSUES REGARDING THE POWER GENERATION EQUIPMENT PROPOSED FOR THIS FACILITY

The Air District received a number of comments regarding the type of electrical generating equipment the applicant intends to use at the Russell City Energy Center and whether it is consistent with the Best Available Control Technology ("BACT") requirements of the Federal PSD permitting program. Although many comments were specific to emissions of individual PSD-regulated pollutants (or potentially PSD-regulated pollutants such as greenhouse gases), a number of them were directed at BACT issues generally, such whether alternative equipment might be cleaner and more efficient in general. In this section the Air District addresses the general comments about BACT for this equipment. Additional pollutant-specific (or operating scenario-specific) BACT comments are addressed in subsequent sections.

Comment II.1. – Currentness of Combustion Turbine Technology:

The District received a number of comments regarding the type of electrical generating equipment the applicant intends to use at the Russell City Energy Center, and in particular whether it will be the cleanest and most efficient equipment consistent with the Best Available Control Technology requirements of the Federal PSD permitting program. Some of these comments stated that the Air District incorrectly based its BACT analysis for the combustion turbines/heat recovery boilers on the equipment that the applicant has already purchased and intends to use at the facility. Some comments questioned whether other equipment besides what the applicant intends to use for the project would be able to achieve lower emission rates. Although many of these comments were specific to emissions of individual PSD-regulated pollutants (or potentially PSD-regulated pollutants such as greenhouse gases), a number of them were directed at whether alternative equipment might be cleaner and more efficient in general.

Response: At the outset, the Air District notes generally that it agrees with the premise underlying these comments that the BACT permit requirements established for a facility need to be based on the emissions performance of the best equipment currently available, and may not be based on a lower level of performance of older equipment simply because an applicant may have already purchased existing equipment. The commenters are incorrect, however, in implying that the Air District bases its BACT determinations on the performance of older equipment in situations where an applicant may have already purchased equipment that it would like to use at a facility. To the contrary, the Air District bases its BACT limits on the emissions performance of the most current technology. Where appropriate, the Air District has not hesitated to impose more stringent limits for this project than were considered achievable in 2002 when the project was first permitted. For example, when the Air District initially proposed to issue this PSD permit, it proposed a NO_2/NOx limit of 2.0 ppm, even though the current BACT limit when the project was initially licensed was considered to be 2.5 ppm.[1] The Air District therefore requires project applicants to comply with the most stringent emissions limits currently achievable for a facility, as defined in the BACT requirements, regardless of whether the applicant has already purchased equipment or not.

[1] *See* June 19, 2007, Final Determination of Compliance; December 8, 2008, Statement of Basis.

For these reasons, in response to these comments the Air District explored whether there was more efficient generating equipment that the facility could use. The Air District has identified "FD3" turbine technology as the current state-of-the-art electrical generating equipment for a facility of this type, as outlined in detail in Section III.B. below. FD3 turbine technology would allow the facility to achieve an overall thermal efficiency of 56.4% (lower heating value), which is the highest efficiency of any similar plant that the Air District reviewed. This FD3 technology is slightly more efficient than the "FD2" technology that the applicant originally proposed. After further discussions with the project applicant, the applicant has agreed to upgrade its equipment to incorporate the more modern FD3 technology. These FD3 upgrades will result in an improvement in the thermal performance of the gas turbines, resulting in a higher efficiency for the plant as a whole. That is, they will result in a reduction in the plant's "heat rate", which is the amount of fuel required to produce a megawatt (MW) of electricity, making the gas turbine's efficiency comparable to the best F-Class turbines available on the market today. The Air District is basing its BACT determinations on this state-of-the-art technology, not on the FD2 technology used in the turbines that the applicant originally proposed.

The FD3 upgrades will consist of decreasing the clearances in the compressor section of the turbine, adjusting the inlet guide vanes and optimizing the control system components. More specifically, the upgrades will include the following:

- The inlet guide vanes will be opened more to increase airflow.
- The existing compressor row 7-15 diaphragm inter-stage labyrinth seal holders will be replaced with honeycomb seals.
- The compressor row 16 blades will be replaced with a new design.
- The gas turbine row 1 blades will be replaced with a new design.
- The gas turbine row 1 ring segments and isolation rings will be replaced with a new improved design.
- The gas turbine row 2 seal housing will be replaced with a new rope seal.
- The gas turbine rows 2 and 3 vane sealing will be enhanced.
- The gas turbine row 4 blade ring assembly, consisting of blade rings, vanes, ring segments and inter-stage seal housing will be replaced with a new design.
- The gas turbine row 4 blades will be replaced with a new design.
- The existing exhaust cylinder will be replaced.

The Applicant will also implement operational and maintenance changes recommended by the original equipment manufacturer to improve performance, reliability and maintainability of the equipment. In addition, the Applicant will replace the control system with Siemens' latest control technology, known as the "T-3000" system.[2]

[2] *See* Email Memorandum re "RCEC: GHGs BACT Analysis Technical Documentation", from K. Poloncarz, Calpine Counsel, to A. Crockett, BAAQMD, April 2, 2009.

With these upgrades, the turbines the applicant has already purchased will, for all emissions performance purposes, be the equivalent of FD3 turbines commercially available today. These upgrades will increase the plant's overall efficiency such that the rate of emissions per unit of energy produced will be reduced, which will allow the facility to meet a BACT standard set by the emissions rate achievable by FD3 turbines. Based on this FD3 technology, the facility will be able to achieve a thermal efficiency of 56.4%, which is the highest efficiency of any similar plant the Air District reviewed. This highly efficient technology will generate fewer emissions for a given amount of power generation than any other similar facility. The Air District is basing its proposed BACT permit conditions on this current technology.[3]

The Air District is therefore basing its BACT permit conditions on the emissions performance of this current state-of-the-art FD3-level technology, and not on some lesser performance level based on older equipment. The Air District notes, however, that it is not proposing permit requirements specifying exactly what equipment must be used to satisfy the applicable BACT permit limits. BACT requires emission limits to be imposed based on the best emissions performance achievable by current state-of-the-art technology, but once the BACT limits are established based on this technology as the Air District is proposing, the specific equipment the facility uses to achieve that limitation is irrelevant. As long as the facility keeps emissions within the BACT emission standards, it does not matter what particular choice of equipment the facility uses to do so. Certainly, from an environmental standpoint the choice is irrelevant because it is the emissions that impact air quality not the make or model of the equipment that generates them. If the applicant can meet current emission standards by upgrading existing equipment, there may be significant benefits to be gained, such as avoiding the costs of purchasing new equipment that would ultimately be borne by ratepayers and avoiding the waste inherent in junking serviceable equipment. But how the applicant meets current emission standards is up to the applicant. What matters from an air quality perspective – and what matters

[3] The BACT analyses for certain specific pollutants and/or specific operating scenarios depend on other factors such as the availability of add-on controls, *etc*. But to the extent that emissions performance is linked to turbine efficiency, the emissions performance from these FD3-equivalent turbines will be the lowest achievable because FD3 turbines are the most efficient for this type of application. The main gist of the comments the Air District received regarding turbine efficiency were primarily directed at greenhouse gases (to the extent that these are regulated NSR pollutants subject to BACT), but the Air District did also receive some comments directed at the efficiency of the equipment for purposes of the BACT analyses for other pollutants as well. The Air District responds that, to the extent that emissions of those other pollutants are a function of turbine efficiency (*i.e.*, the amount of criteria pollutants emitted is proportional to the amount of fuel burned in generating power output), the Air District's turbine efficiency analysis would be the same for criteria pollutants as it would be for greenhouse gases. The Air District has reviewed the turbine equipment available for this type of facility and has found that the FD3-equivalent turbines are the most efficient in terms of fuel used per unit of power output. Thus, the facility will emit the lowest amount of greenhouse gases per unit of power generated, and will also emit the lowest amount of criteria pollutants per unit of power generated (to the extent that criteria pollutant emissions are proportional to fuel usage). The comments provided no information to suggest that an efficiency analysis undertaken for the purpose of finding the most efficient turbines for greenhouse gases would not also be appropriate to find the most efficient turbines for criteria pollutants as well.

for purposes of the Federal PSD Permit requirements – is whether the limits established in the permit reflect the maximum emission reductions achievable for the source using current technology. As demonstrated in the Air District's BACT analyses (as set forth in more detail in the rest of this document), the limits the District is imposing on this facility are all based on current technology. Since the limits that the facility will be subject to are based on current technology, issues such as the date of manufacture or purchase of the specific equipment the applicant may choose to install are not relevant for purposes of the Federal PSD Permit.

The Air District published this additional analysis based on the comments received during the first comment period. It did not receive any further substantive comments on the District's conclusions that it is basing its BACT permit conditions on current state-of-the-art technology, and not on outdated technology simply because the applicant already owns existing equipment as these comments implied. The only further comments the Air District received on this issue during the second comment period were general assertions that the equipment proposed for the facility is old and does not reflect current technology. These further comments did not identify any specific reasons why the Air District's assessment outlined above that its BACT analysis is based on current best technology is incorrect. The Air District therefore finds no reason in these further general comments to conclude that its assessment is not correct. For all of these reasons, the Air District disagrees that the BACT requirements it is imposing in the Federal PSD Permit are based on old, outdated equipment.[4]

Comment II.2. – Use of Duct Burners to Generate Additional Power:

The District also received comments asserting that the proposed design of using duct burners to generate additional steam to power the steam turbine is not the most efficient method to generate additional power to meet peak demand. These comments asserted that duct burners are inefficient and reduce the fuel efficiency (and thus increase the air emissions) of the facility. They stated that the Air District should have considered alternatives to duct burners, such as simple-cycle turbines or solar alternatives, to meet peak load demand.

Response: In response to these comments, the Air District considered further whether the use of duct burners satisfies the BACT requirement. Upon further consideration, the District has concluded that there are no more efficient alternatives that would meet the power generation

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[4] In one specific comment, commenters pointed to a set of PowerPoint slides from Siemens Corp. and suggested that the information in the slides shows that there are superior alternatives to the proposal for the facility, published at www.netl.doe.gov/technologies/coalpower/turbines/refshelf/papers/Siemens_SGT6-5000F%20(W501F)%20Engine%20Enhancements%20to%20Improve%20Op.pdf. These commenters also referenced a document entitled "Advanced Power Plant Development and Analyses Methodologies Final Report", published at www.netl.doe.gov/technologies/coalpower/fuelcells/seca/pubs/reports/UCI%20Finall%20Report%20DE-FC26-00NT40845.pdf, although they did not claim that it implicates the proposed facility or explain how it could impact the proposed permitting action. These commenters also cited a 1997 paper from EPRI regarding startup of a Siemens peaking turbine (www.mydocs.epri.com/docs/public/TR-108609.pdf), although again they did not explain how it has any bearing on the current permitting action. The Air District has reviewed these documents and did find anything to suggest that its permitting analysis is flawed in any respect.

needs for which this facility was designed. The facility is designed to meet a maximum power demand of nominally 600 megawatts, but a 2x1 combined-cycle facility without duct burning can meet a nominal demand of only 550 megawatts.[5] Duct burning is an efficient way of generating additional power to meet peak demand from the combustion turbine exhaust. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine. In response to these comments, the Air District evaluated whether the additional peak capacity could be more efficiently provided by other technologies besides duct burning.[6]

The Air District first evaluated the alternative of replacing the duct burners with simple-cycle generating technology (*i.e.*, "peaker" turbines) that could generate approximately the same amount of energy during peak demand periods. Simple-cycle turbines would not be more efficient than duct burning here, however. To the contrary, simple-cycle turbines of similar capacity would have a higher heat rate (*i.e.*, take more fuel to produce a unit of power) than duct burning. The incremental additional heat rate using duct burning to generate peak capacity (rated at 46.3 MW) is 7,595 Btu/kWhr (LHV).[7] In comparison, a basic GE LM6000 gas turbine generator set, rated at 42.3 megawatts, would have a heat rate of 8,308 Btu/kWh (LHV); with additional features, a GE LM6000 Sprint ("Spray-Intercooled Turbine"), rated at 46.9 megawatts, would have a heat rate of 8,235 Btu/kWh (LHV).[8] Duct firing will therefore be a

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[5] Combustion turbines come only in discrete size classes, and so it is not always possible to design a facility to meet the demand called for using turbines alone. Where it is not possible, some way of making up the additional capacity must be used. (Note that these are nominal capacities; actual power output from a specific facility at any given time depends on a large number of design and operational variables.) The facility's design capacity cannot be achieved here by use of a 2x1 turbine configuration alone without some additional peak power.

[6] It is not clear whether the BACT analysis requires a consideration of alternatives to duct firing to meet peak capacity demand. The BACT analysis is not intended to require the applicant to change its design from construction of a combined cycle to simple cycle facility or to eliminate and replace key elements of its design with different sources. (*See*, *e.g.*, *In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, 51-52 (EAB 2003) (finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility"); *see also In re Prairie State Generating Co.*, PSD Appeal No. 05-05, 13 E.A.D. __, slip op. at 32, *aff'd sub. nom Sierra Club v. U.S. Envt'l Protection Agency*, 499 F.3d 653 (7th Cir. 2007) (referencing the EAB's recognition in *In re Kendall New Century Development* that "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility").) This issue is moot here, however, as the Air District has concluded that there are no superior alternatives even if such an analysis were required.

[7] *See* Russell City Energy Center Heat Balance Diagrams.

[8] GE Aero Energy Products, brochure, LM6000 SPRINT™ Gas Turbine Generator Set, available at: www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf.

more efficient method of generating peak capacity than installation of the most efficient form of simple-cycle generation capacity the Air District is aware of. The Air District therefore concludes that the use of a simple-cycle turbine would not provide any advantage over duct burning.

Moreover, even if it were not for the superior performance of Russell City Energy Center's duct burners in comparison to an LM6000, replacement of duct burners with a separate simple-cycle unit would likely be eliminated from consideration as BACT based upon the significantly greater cost and ancillary environmental impacts. According to a report prepared by the California Energy Commission, the cost to replace the proposed Russell City Energy Center's peaking capacity with a simple cycle plant would be approximately \$507.98 per MWhr for an investor-owned utility (IOU) plant or \$647.28 per MWhr for a "merchant" plant.[9] In contrast, the total estimated cost for a 550-MW combined cycle plant with duct firing is approximately \$95.59 or \$103.52 per MWhr for an IOU or merchant plant, respectively;[10] whereas the cost for a combined cycle facility without duct firing is estimated for an IOU and merchant plant at \$94.47 or \$102.19 per MWhr, respectively.[11] In light of these estimates, the marginal cost associated with duct firing at a facility like the proposed Russell City Energy Center would appear substantially more favorable than the cost to replace its peak capacity with a separate simple-cycle unit. The Air District therefore concludes the cost of requiring simple-cycle peak power generation would be obviously excessive, and thus would not be required as BACT for this additional reason as well.

The Air District also examined the potential for using solar thermal technology as an alternative to using duct burners in response to this comment.[12] The Air District reviewed the approach taken with the proposed Victorville 2 Hybrid Power Project, which utilizes solar technology to eliminate some of the need for duct burning to address peak demand. The Victorville Project will be a 570-MW facility located in the Mojave Desert and will consist of natural gas-fired, combined-cycle generating equipment integrated with solar thermal generating equipment. The solar thermal component of the Victorville "hybrid" Project will consist of a series of diurnal, single-axis-tracking parabolic trough solar collectors laid out in parallel rows aligned on a north-south horizontal axis. Each solar collector will track the sun from east to west to assure that it continuously reflects the greatest amount of sunlight possible onto a "linear receiver", which contains a heat transfer fluid that circulates through the receiver and returns to a series of heat exchangers, where it is used to generate high-pressure steam for two heat recovery steam

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[9] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Final Staff Report, December 2007, CEC-200-2007-011-SF, at pp. 10, 12; available at: www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF. An LM6000 is the equivalent of "Small Simple Cycle" (50 MW) in the Energy Commission's report. Dollar figures are given in nominal 2007 dollars.

[10] *Id.* at p. 12.

[11] *Id.* at p. 10.

[12] Requiring a facility to be redesigned to use solar-powered generation instead of natural gas would constitute "redefining the source" in contravention of the Federal PSD BACT requirements. The Air District considered the potential for a solar alternative nonetheless, and has concluded that even if BACT could be construed to allow a redesign of the project in this manner, a hybrid solar alternative would not be available here as explained below.

generators (HRSGs). The solar thermal input is intended to provide approximately 10% of the power generated by the facility during peak periods. Use of solar thermal equipment is projected to increase the overall thermal efficiency of the combined-cycle plant from 52.7% to 59% (LHV) because it would allow the facility to reduce firing of the duct burners during peak periods and replace that peak capacity with the input from the solar thermal generating equipment.[13] In comparison to Victorville's 59% efficiency rating (LHV) during such periods, the Russell City Energy Center's efficiency rating would be 56.44% (LHV) during periods of duct burning.[14]

A solar alternative to duct burning would not be feasible for the Russell City facility, however, because there is far less available area at the project location than in the Mojave Desert, and the compact site would not provide adequate space for installation of a solar collectors. To construct a solar thermal plant to replace some of the peak capacity from duct burning would need 275 acres of land,[15] which would not be feasible given the space-constrained project site on the edge of the San Francisco Bay.[16] Redesigning the project to incorporate a solar system like Victorville's would therefore require the facility to be moved to another location, making it impossible to achieve the project objectives served by the current location, which include "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices",[17] and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[18] Requiring additional space to build a solar system would also eliminate the environmental benefits of locating adjacent to the City of Hayward's waste water treatment plant so the facility can recycle approximately 4 million gallons per day of effluent from the plant and eliminate discharges of that waste water to the San Francisco Bay, and of locating at a

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[13] City of Victorville, *Application for Certification, Victorville 2 Hybrid Power Project*, February 28, 2007, at 2.1-2.14; available at www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/. Again, it is not clear that the BACT requirement is intended to involve replacement of duct firing to meet peak capacity demand with a completely different type of facility design, but that issue is moot because the Air District has found that solar peaking capacity would not be feasible here.

[14] *See* Table, Comparison of FD3 Turbines with and without duct burner firing, prepared by Alex Prusi, P.E., Director of Engineering, Calpine, April 2, 2009.

[15] *See* City of Victorville, *Application for Certification, Victorville 2 Hybrid Power Project*, February 28, 2007, at p. 2-3; available at www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/.

[16] The project site for the Russell City Energy Center is a 16.5-acre area located in the West Industrial District of Hayward, California, adjacent to the City of Hayward Water Pollution Control Facility and near existing transmission facilities. (*See* California Energy Commission, *Final Commission Decision, Russell City Energy Center* (October 2007) (available at www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF) (hereinafter, "2007 Energy Commission Decision"), at p. 10.

[17] California Energy Commission, *Commission Decision, Russell City Energy Center* (July 2002, P800-02-007) (hereinafter, "2002 Energy Commission Decision"), pp. 17 (available at: www.energy.ca.gov/sitingcases/russellcity/index.html).

[18] Calpine, *Application for Certification, Russell City Energy Center* (May 2001) (hereafter, "RCEC Application for Certification"), at pp. 9-2 – 9-22 (available at: www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/vol-1/).

previously-developed brownfield site. For these reasons, the Air District has found that thermal solar peaking capacity is not an available alternative to reduce the facility's use of duct burning to generate peak capacity.

For all of these reasons, the Air District disagrees with the comments that there are alternative methods to generate the additional peak capacity needed to meet the facility's design load that should be required as part of a BACT analysis. The Air District published this further analysis in the Additional Statement of Basis and made it available for further comment during the second comment period. During the second comment period, the Air District received comments questioned the District's assertion that a hybrid solar facility such as the Victorville project would not be feasible at the proposed project location. These comments claimed that the conclusion that 275 acres of land would be needed for such a facility was based on solar technology as of 2001, and that the technology may have since changed to allow a hybrid solar plant using less space. The comments also claimed that there is over 275 acres in the San Francisco Bay and in industrial areas of the City of Hayward, and that the applicant should consider whether these types of areas could be used for a hybrid solar facility. The comments also suggested considering whether a facility using half the area or twice the area of the District's estimated 275 acres could be feasible. Finally, some comments also noted that the City of Hayward recently published a Request for Proposals for an adjacent solar facility.

The Air District disagrees that anything in these additional comments provides any reason to conclude that a solar hybrid alternative would be feasible here, even if the BACT analysis could allow the District to require such a redesign of the facility. As discussed in the Additional Statement of Basis, the design requirements for the facility call for approximately 50 MW of additional power generation capacity. (*See* Additional Statement of Basis at pp. 9-12.) It is simply not possible to site 50 MW of solar capacity at the facility's location, which is only 16.5 acres in size.[19] All of the hybrid solar facilities the Air District is aware of with sufficient capacity to satisfy 50 MW of load show that current solar technology cannot produce anywhere near 50 MW on a site of this size. The proposed Victorville project described above would require 275 acres to produce approximately 50 MW – and those acres are in the Mojave Desert.[20] The proposed Palmdale Hybrid Power Project, a similar natural-gas powered facility with additional solar thermal generating equipment that would provide approximately 10% additional capacity, will require approximately 250 acres for its solar filed, with an overall site size of 377

[19] Some comments noted that the analysis in the Additional Statement of Basis discussing the whether a hybrid solar facility could be used incorrectly stated that the current proposed project site is 14.7 acres. These commenters pointed out that this site size refers to the project location that was initially proposed, not the current location. The correct size of the current project location is 16.5 acres. (*See* 2007 Energy Commission Decision, *supra* note 16, at p. 10.) The additional 1.8 acres would not allow the project to accommodate a hybrid solar design, and so this misstatement does not make any difference in the outcome of the Air District's analysis.

[20] The solar field will encompass approximately 250 acres, while the power-plant site overall is 275 acres. *See* City of Victorville, *Application for Certification, Victorville 2 Hybrid Power Project*, February 28, 2007, at p. at 2-3, 2-12; available at www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/.

acres.[21] Solar-only projects also require a large amount of land, as evidenced by the proposed Ivanpah Solar Electric Generating System, which will require 3,400 acres to generate 400 MW;[22] the proposed Carrizo Energy Solar Farm, which will require 640 acres to generate 177 MW;[23] and the proposed Beacon Solar Energy Project, which will require 2,012 acres to generate 250 MW[24]).

Furthermore, nothing in these comments provides any contrary evidence to show that a hybrid solar option could be implemented at the facility's location. Some comments did reference the fact that the City of Hayward has proposed a 1,000-kW (1 MW) photovoltaic solar project located at the City's Water Pollution Control Facility near the Russell City site.[25] The project will use solar energy to partially offset the electricity currently acquired from PG&E for wastewater treatment.[26] The photovoltaic system will be installed on the ground and occupy about 8 acres within the existing Water Pollution Control Facility site.[27] While a photovoltaic system can substantially offset the electricity demands of the Water Pollution Control Facility, it cannot provide an alternative to duct burning for providing 50 MW of additional capacity at the Russell City Energy Center. Assuming a potential of 1 MW per 8 acres, 400 acres would be required to generate the 50 MW needed by the Russell City Energy Center to meet peak demand. As such, replacement of the proposed facility's duct burners with photovoltaic solar generating capacity is not a feasible alternative for the project.

The Air District therefore concludes, based on all of the evidence before it, that it would not be possible to implement a hybrid solar facility for this project without requiring the facility to be moved to another location, which would make it impossible to achieve the project objectives served by the current location, and would eliminate the environmental benefits of locating adjacent to the City of Hayward's waste water treatment plant, near existing transmission facilities, and at a previously-developed brownfield site.[28]

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[21] Palmdale Hybrid Power Project, *Application for Certification* (July 2008) at 2-1, 2-4, available at: www.energy.ca.gov/sitingcases/palmdale/documents/applicant/afc/volume_01/.
[22] *See* California Energy Commission, Ivanpah Solar Electric Generating System (Docket No. 07-AFC-5), available at: www.energy.ca.gov/sitingcases/ivanpah/index.html.
[23] *See* California Energy Commission, Carrizo Energy Solar Farm Power Plant Licensing Case (Docket No. 07-AFC-8), available at www.energy.ca.gov/sitingcases/carrizo/index.html.
[24] *See* California Energy Commission, Beacon Solar Energy Project (Docket No. 08-AFC-2), available at: www.energy.ca.gov/sitingcases/beacon/index.html.
[25] City of Hayward, Water Pollution Control Facility, 1,000 kW Photovoltaic Renewable Energy Project, Environmental Initial Study/Draft Mitigated Negative Declaration (Sept. 2009), available at: http://user.govoutreach.com/hayward/faq.php?cid=11037.
[26] *Id.* at 1.
[27] *Id.* at 5.
[28] *See generally* discussion in Additional Statement of Basis at p. 12. The project objectives include "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices" and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco." *Id.* (citing California Energy Commission, *Commission Decision, Russell City Energy Center* (July 2002, P800-02-007) at 17, available at

Comment II.3. – Design of Facility For Intermediate-To-Baseload Service:

The District also received comments noting that the facility would be operated to meet contractual load and spot sale demand, and may not operate on a full-time, base-loaded basis. These comments questioned the anticipated operating mode of the proposed Russell City Energy Center, suggesting that if it were intended for load-following or other duty that would involve frequent startup and shutdown events, the Applicant should be required to construct a fast-start-capable, peaking-to-intermediate duty plant instead.

Response: The Air District has considered this issue further in light of these comments. The Air District notes that the Federal PSD Permit process is designed to ensure that a proposed facility will be as low-emitting as possible (among other requirements). It is not designed to require an applicant to propose a different type of project of a different fundamental scope and design, for example to substitute a simple-cycle peaking plant instead of a combined-cycle intermediate-to-baseload project as the commenters suggest here.[29] Moreover, it would not make any sense from an emissions standpoint to require a simple-cycle facility for the purpose that this facility is intended to be used for, which is to serve intermediate-to-baseload capacity. Simple-cycle facilities are less efficient than combined-cycle facilities, which recover the heat from the turbine exhaust (which would simply be emitted and wasted in a simple-cycle facility) and use it to generate additional electricity. Simple-cycle facilities are therefore generally inferior to combined-cycle facilities, except for applications where the generating capacity must come on-line in a very short time frame, which is not the case with the uses for which this facility has been proposed and designed. The Air District therefore disagrees that it should require the applicant to redesign the facility as a simple-cycle peaking facility. (*See also* discussion in Response to Comments VIII.C.2. and VIII.D.1.)

Comment II.4. – Sources of Emissions Estimates:

Some comments also criticized the Air District for relying on emissions estimates from the project applicant and from the CEC in its explanation of the emissions from the project (*see, e.g.*, discussion on pp. 12-13 of the December 8, 2008, Statement of Basis).

Response: The Air District disagrees with the comments that it is inappropriate to use these sources of information in assessing the potential emissions from the project. To the contrary, the project applicant and the CEC are among the best sources of information about potential emissions from the facility based on their detailed knowledge and understanding of the proposed project and the type of operation involved. Moreover, the Air District has not seen any suggestion that any of the emissions estimates the Air District relied on may be unreliable in any way, or that there may be alternative sources of emissions estimates that it should consider instead, and the commenters have not provided any information to support such a conclusion. And in any event, the Air District is proposing to turn the emissions estimates into enforceable emissions limits in the PSD permit, along with monitoring and recordkeeping requirements to

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www.energy.ca.gov/sitingcases/russellcity/index.html; RCEC Application for Certification, *supra* note 18, at pp. 9-3 - 9-4.

[29] This principle has been well established by the Environmental Appeals Board in reviewing PSD permits. *See, e.g.*, *In re Prairie State Generating Co.*, *supra* note 6, slip op. at 32; *In re Kendall New Century Development, supra* note 6, at 51-52.

ensure that actual emissions stay below these limits. Thus, if the underlying estimates turn out to be inaccurate and actual emissions exceed the estimates as they have been incorporated into the permit limits, the facility will be in violation of its permit and will have to shut down or curtail operations unless it can fix whatever problems are causing the increased emissions. For all of these reasons, the Air District disagrees that it is inappropriate to consider emissions estimates from the project applicant or from the CEC in its permitting analysis.

The Air District published this analysis in the Additional Statement of Basis and invited the public to comment on it during the second comment period. In particular, the Air District invited the public to provide any further information as to how and why these sources of information may be unreliable and whether there are alternative sources of emissions information that would be relevant to the PSD permitting process for this facility that the Air District should take into account. The Air District did not receive any further comments identifying any reasons how or why these sources could be unreliable or stating that the Air District should rely on other sources instead. The Air District therefore concludes that that relying on information from the applicant and the CEC is appropriate in a PSD permitting analysis, and disagrees with the comments that suggested otherwise.

The Air District did receive further comments during the second comment period that questioned the District's assertions that if the applicant and manufacturer's data on emissions performance turn out to be incorrect and the equipment at the facility cannot in fact meet the BACT permit limits, the facility will be in violation of its permit conditions and will have to shut down or curtail operations unless it can fix whatever problems are causing the increased emissions. These comments claimed that these assertions were incorrect based on the experiences of other power plants. They cited the Calpine Metcalf and Sutter power plant and implied that those facilities are being allowed to pollute more than their permit limits (although the comments stated that the facilities had applied for and received amended permit conditions, which suggests that the facilities are not in fact exceeding their permitted limits). They also cited the PG&E Gateway facility, which they stated is not being required to shut down or curtail operations despite not having a current PSD permit. The comments implied that these facilities show that permitted facilities do not have to comply with their permit conditions. The comments also suggested that the District impose a condition in the permits that the facility cannot apply for or receive modified permit conditions.

In response to these further comments, the Air District disagrees that this facility will be allowed to exceed its permit limits once they are established. Permit limits create legal obligations and EPA regularly takes action to enforce them. The PG&E Gateway facility, cited in the comments, is an example of such enforcement action. When EPA determined that the facility was constructed in violation of the Federal PSD Permit requirements, it issued a Finding and Notice of Violation for the facility, filed a Complaint in federal District Court, and has proposed a Consent Decree which, if approved by the Court, will require PG&E to pay a monetary penalty and take additional steps to ensure future compliance. Some commenters have disagreed with certain elements of the proposed Consent Decree, for example in the size of the monetary penalty EPA is seeking or the terms of the injunctive relief, but there can be no dispute that EPA is taking enforcement action to address the violations it has identified. (*See also* discussion in Response to Comment XIX.22.) Moreover, with respect to the Metcalf and Sutter facilities, the

Air District is not aware of any violations of PSD permit conditions at those facilities that have not been subject to enforcement action, and the comments have not identified any. To the extent that those facilities have had their permits amended, permit amendments can be granted only if the amendments comply with applicable legal requirements, including PSD requirements. There is nothing inappropriate about such amendments, and the permitting process needs to accommodate amendments to allow facilities to modify and upgrade their equipment over time. The Air District therefore disagrees that it should (or could) include a condition that the facility cannot apply for or receive modified permit conditions. To the extent that the facility requests a permit amendment in the future, the Air District will address the appropriateness of the amendment at the time based on applicable legal requirements.

Comment II.5. – Review of Individual System Components:

The Air District also received comments claiming that it should not just look at the overall emissions performance achievable by other combined-cycle facilities as a whole. These commenters claimed that the District should review each of the elements of the overall system, including the turbine, HRSG, and add-on control devices, in determining what would be the best achievable emissions performance.

Response: The Air District agrees that in certain circumstances a BACT analysis should examine individual system components to determine what level of emissions performance is achievable from the power generating system as a whole. Where appropriate, the Air District has undertaken this level of analysis and is imposing BACT limits based on this level of analysis. In other cases, where the achievable emissions performance from the system as a whole is well-understood and the individual system components have been used together in the same way at many other similar sources, the analysis can look to the overall performance achieved by similar sources without a detailed analysis of each individual system component. The NO_2 emissions performance of gas turbines using Dry Low-NOx combustors in conjunction with an SCR system is one such example. Ultimately, what level of detail needs to be applied in the BACT analysis is subject to a rule of reason that must be applied in each specific case. The Air District agrees that in appropriate cases, the BACT analysis must look at individual system components to determine how the system as a whole can be configured to achieve the lowest BACT emissions level, and has done so here. The Air District found nothing in the comments to suggest that it failed to apply the appropriate level of detain in any particular BACT analysis, and no commenter suggested that any of the BACT limits should be set at a lower level based on a more detailed review of individual system components that the Air District conducted.

Comment II.6. – Specific Turbine Details:

Commenters asked for detailed information about the combustion turbines that the manufacturer intends to use at the facility, such as turbine serial numbers, dates of manufacture, cost, *etc*.

Response: Specific details such as these are not relevant to determining the Best Available Control Technology and applicable permit limits for this equipment or for analyzing the potential air quality impacts of the facility, and so the Air District has not sought such information from the applicant. For example, if the Air District determines that a certain type of turbine is BACT and imposes a BACT permit limit based on the achievable emissions performance for such a turbine, it makes no difference which particular turbine is used (*e.g.*, which particular serial number) as long as the facility complies with the applicable permit conditions. The Air District disagrees that such specific information is relevant to the Federal PSD Permitting analysis. To the extent that information about particular types of turbines is relevant (*e.g.*, costs, ancillary environmental or energy impacts, relative efficiency, achievable emissions performance standards, *etc*.) the Air District has sought that information and provided it in the relevant areas of its permitting analysis.

The Air District included this further discussion of the issue in the Additional Basis, and received comments during the second comment period that specific equipment details such as turbine serial numbers, dates of manufacture, cost, *etc.*, are important because the commenters believe that the turbines may be used or remanufactured turbines. The comments asserted that if they are overhauled turbines, their pollution characteristics may differ from the original manufacturer's specifications. The Air District has no information on which to evaluate these claims that the turbines that Calpine intends to use at the facility may be used or remanufactured, and the comments have not provided any information to support this contention beyond mere speculation. But regardless, it does not matter whether the turbines are new or used as long as they can meet the BACT emissions limits, which are based on the best performance of current, state-of-the-art equipment. The Air District disagrees that there is anything about such specific, detailed turbine information that is relevant to the PSD permit analysis, or that the Air District needs to obtain and publish such information as part of the permit process.

Comment II.7. – Technology-Forcing BACT Requirements:

The Air District received comments noting that the BACT requirement is intended to be technology-forcing, and that the greatest achievable level of control will improve over time as new control technologies develop. These comments stated that the District is relying on emissions performance achieved at existing facilities, and not looking at what the best achievable performance for a new facility is. These comments also criticized the District for providing a "compliance margin" by proposing BACT limits that were somewhat higher than the best emissions performance achieved by comparable facilities.

Response: The Air District agrees that the BACT requirement is intended to be technology-forcing and that in general BACT limits will improve over time as new technologies develop. The stringent permit limits the Air District is imposing in this permit, which are more stringent than similar BACT limits imposed in other permits issued in the past, are evidence of this fact. The Air District disagrees, however, that it has not implemented the technology-forcing BACT requirement properly for this facility. As documented in the District's Statement of Basis, Additional Statement of Basis, and other supporting documents, the Air District did canvass the current state-of-the-art control technologies, including technologies that are currently in use and technologies that are being newly developed. Based on these analyses, the Air District imposed the most stringent permit limits achievable in accordance with the BACT requirements. The Air District has not necessarily based its limits on the lowest emissions ever achieved in a test result from a particular technology, and where necessary it has provided a reasonable and justified compliance margin to ensure that the limits are achievable under all operating scenarios. But the Air District disagrees that doing so is inappropriate. To the contrary, providing an appropriate compliance margin is required under BACT to ensure that the BACT limits are achievable. For these reasons, the Air District disagrees with the comments that its approach to setting BACT limits is inconsistent with the federal PSD requirements.

III. GREENHOUSE GAS ISSUES

As the Air District explained in the Statement of Basis and Additional Statement of Basis, the project applicant has voluntarily agreed to accept binding, enforceable limits on greenhouse gas emissions despite EPA's indications that greenhouse gas regulations are not subject to the PSD permit requirements of 50 C.F.R. Section 52.21 at this time. The Air District therefore proposed greenhouse gas BACT limits in its initial draft permit in December of 2008. The Air District received numerous comments on that initial proposal during the initial comment period, and it then substantially revised the analysis based on the insightful comments received and on additional analysis by District staff and submissions by the applicant. The Air District then published its revised proposal in the revised draft permit in August of 2008, and received further comment during the second public comment period. The Air District is now finalizing greenhouse gas limits in the PSD permit it is issuing for the Russell City facility, and it responds to the comments received on the greenhouse gas BACT issues as set forth below.

A. Applicability of PSD Permit Requirements to Greenhouse Gas Emissions

Comment III.A.1. – Applicability of Federal PSD Program to Greenhouse Gas Emissions:
A number of comments claimed that CO_2 (as well as other greenhouse gases) are pollutants "subject to regulation" under the CAA, and are therefore subject to PSD review.

Response: In the Statement of Basis and Additional Statement of Basis, the Air District summarized the current state of recent regulatory developments regarding whether greenhouse gases are subject to regulation under the federal PSD program. As the Air District noted in those documents, EPA's Environmental Appeals Board found in November of 2008 in the *Deseret Power* case that EPA as an agency has the discretion to determine whether greenhouse gases should be subject to PSD regulation or not, but had not at that time adopted any definitive policy position on the issue.[30] The EAB also suggested that it may be more appropriate for EPA to address this issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. The issue was thus in a highly unresolved state when the Air District issued its initial proposal on December 8, 2008. Then, on December 18, 2008, EPA issued a policy memorandum in response to the EAB's *Deseret Power* opinion. The impact of EPA's December 18 memorandum is that EPA is not requiring greenhouse gases to be regulated under the Federal PSD permitting program, at least as of this time.[31] This continues to be the case

[30] *See In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, slip op. at 63-65 (EAB Nov. 13, 2008).

[31] *See* Memorandum, Stephen L. Johnson, Administrator, *EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*, December 18, 2008 (hereinafter, "PSD Interpretive Memo"); notice provided at 73 Fed. Reg. 80300 (Dec. 31, 2008). EPA has proposed to reconsider the position set forth in the PSD Interpretive Memo, but it is proposing to affirm its interpretation with respect to whether greenhouse gases are subject to regulation under the PSD program. *See Prevention of Significant Deterioration (PSD): Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, Proposed Rule*, 74 Fed. Reg. 51,535, 51,545-46 (Oct. 7, 2009).

currently. EPA has recently determined that greenhouse gases endanger public health and welfare, which will pave the way for EPA to adopt regulations limiting greenhouse gases from motor vehicles and other sources.[32] EPA has also proposed new regulations for greenhouse gas emissions from cars and trucks which, if finalized, would make greenhouse gases subject to PSD regulation.[33] But these regulations are still only at the proposal stage, and EPA continues to treat greenhouse gases as not yet subject to the PSD program until such time as specific regulations for greenhouse gases from specific sources are adopted and take effect. The Air District is therefore finalizing the permit on the basis that greenhouse gases are not subject to PSD at this time, since EPA's new regulations have not yet been finalized. However, as explained in the Statement of Basis and Additional Statement of Basis, the applicant has voluntarily requested the District to undertake a greenhouse gas BACT analysis and impose enforceable greenhouse gas BACT limits as if greenhouse gases were currently subject to PSD requirements. The Air District has done so, and is imposing greenhouse gas limits in the final permit based on the applicant's voluntary agreement to be subject to these requirements. The Air District therefore disagrees with these comments that greenhouse gases are subject to PSD requirements, but concludes that the issue is moot because the facility would satisfy all PSD requirements for greenhouse gases even if they were legally applicable at this time.

<u>Comment III.A.2. – Regulation of Greenhouse Gas Emissions Under Other Authorities:</u>
A few comments argued that greenhouse gases should be subject to regulation in this permit for other reasons as well. One implied that the District could impose greenhouse gas limits in this permit under authority of California law; and others claimed that greenhouse gases should be regulated (i) because an EPA website recognizes climate change impacts of greenhouse gases and (ii) in light of the U.S. Supreme Court decision in *Massachusetts v. EPA*.

Response: The District disagrees that it could impose greenhouse gas conditions under California law (or could impose any other state-law conditions, for that matter) in a federal PSD permit. It is certainly true that greenhouse gas issues are the subject of various California statutes and are being addressed by various California regulatory agencies, including the Air District, but that does not mean that the District can impose permit conditions under California law in a federal permit issued on behalf of the federal EPA.

The District also disagrees that simply because greenhouse gas impacts are noted on an EPA website that EPA considers them "subject to regulation" for purposes of PSD permitting. EPA is free to opine about air pollution issues on its website without making them "subject to regulation" for PSD purposes. Nothing in the website references cited by the commenters suggests that EPA has established that greenhouse gases are "subject to regulation" under the PSD program.

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[32] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act (Dec. 7, 2009).

[33] *See Proposed Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards* (GHG Light Duty Vehicle Rule), 74 Fed. Reg. 49,454 (Sept. 28, 2009), issued jointly by EPA and the National Highway Transportation Safety Administration (NHTSA); *see also Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule*,74 Fed. Reg. 55,292 (Oct. 27, 2009).

The District also disagrees with the comments' characterization of *Massachusetts v. EPA* as holding that greenhouse gases are "subject to regulation" under the Federal Clean Air Act. That case determined that greenhouse gases are within the definition of "air pollutant" as used in the Clean Air Act; it did not address the question of whether greenhouse gases are pollutants that are "subject to regulation" under the Clean Air Act.[34]

Comment III.A.3. – Regulation of Greenhouse Gases as a Contributor to Criteria Pollutant Formation:

The Air District also received comments that raised an issue concerning greenhouse gases involving the potential for CO_2 emissions to contribute to increased ozone and particulate matter pollution in the vicinity where the CO_2 emissions occur. These commenters cited recently-published research findings by Mark Z. Jacobson, a researcher at Stanford University, who has posited that locally-emitted CO_2 will form "domes" over urban areas where it is emitted, which will cause localized temperature increases under the "CO_2 domes", and the localized temperature increases will in turn increase the rate of formation of ozone and particulate matter in such areas.[35]

Response: The Air Disagrees that the recent research paper cited by these commenters establishes that the Air District should consider greenhouse gases to be pollutants subject to regulation under the federal PSD program. The Air District notes that the concern expressed in this paper is similar to the general concern that has been expressed about greenhouse gases and the secondary pollution impacts that would arise from warmer temperatures on a global scale. This study is interesting in that it is the first time (that the Air District is aware of) that scientific research has focused on these issues on a local scale. With respect to whether the paper's findings mean that the Air District should treat greenhouse gases as pollutants "subject to regulation" for PSD permitting purposes, the Air District first notes that concerns about temperature increases from the greenhouse effect having secondary impacts on criteria pollutant formation have been known for some time, and yet have not led EPA to treat greenhouse gases as "subject to regulation" at this point as outlined above. The Air District is bound to follow EPA guidance with respect to the Federal PSD program, and so the Air District does not have the discretion to depart from EPA's position in response to a study such as this one. Moreover, since concerns about secondary pollutant effects from warming temperatures globally have not led EPA to consider greenhouse gases "subject to regulation" at this stage, it seems unlikely that consideration of such concerns on a local scale would do so either (at least, at this point in the evolution of EPA's approach to greenhouse gas regulation). This point is especially applicable here, where the first research supporting this hypothesis has only just emerged and there has not yet been time for a scientific consensus to develop around it. But in any event, as with all of these arguments about whether greenhouse gases should be considered "subject to regulation",

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[34] *See generally In re: Christian County Generation, LLC*, PSD Appeal No. 07-01, 13 E.A.D. __, slip op. at 7 n. 12 (EAB Jan. 28, 2008).

[35] *See The Enhancement of Local Air Pollution by Urban CO2 Domes*, Mark Z. Jacobson (Oct. 3, 2009) (hereinafter, "Jacobson Paper") (available at: www.stanford.edu/group/efmh/jacobson/CO2loc0709EST.pdf). Note that some commenters cited an earlier version of this paper dated April 3, 2009. Dr. Jacobson has since posted an updated version.

the issue is moot because the applicant has voluntarily agreed to have the Air District treat greenhouse gases as if they are regulated and to impose greenhouse gas BACT limits, as the Air District has done.

B. Greenhouse Gas BACT Technology Analysis For Combined-Cycle Power Generation Trains

In order to derive appropriate BACT limits for greenhouse gas emissions, the Air District conducted an assessment of available and feasible control technologies. (*See* Statement of Basis at pp. 59-61; Additional Statement of Basis at pp. 17-24.) The Air District addresses comments it received on these issues here.

Comment III.B.1. – Feasible Control Technologies for Greenhouse Gas Emissions:
During the initial comment period, no commenters disagreed with the District's assessment that the only feasible control technology for reducing greenhouse gas emissions is to use the most efficient electrical generating technology, and that at present there are no feasible post-combustion add-on controls. One commenter expressly stated its agreement with the District's assessment that the only currently feasible control option for CO_2 is more efficient energy production. The Air District noted the lack of disagreement on this point in its Additional Statement of Basis, and in the second comment period some commenters did express disagreement with the Air District's conclusion that carbon sequestration is not a feasible control technology at this point in time. These comments stated that subterranean sequestration and bio-sequestration of pollutants in algae-producing ponds may be viable alternatives.[36]

Response: In its December 2008 Statement of Basis, the Air District considered carbon capture and sequestration but eliminated it as an available control technology for purposes of its BACT analysis because it cannot feasibly be implemented on a large-scale power plant at this point in time.[37] The Air District provided two main reasons for this conclusion. First, emerging carbon capture and sequestration technologies are in their infancy and are not currently feasible for projects such as the Russell City Energy Center. In particular, there are currently no carbon capture and sequestration systems commercially available for full-scale power plants in the United States. Second, even if carbon capture and sequestration were sufficiently developed, the feasibility of a system for a particular power plant would depend on the availability of appropriate sequestration sites in the vicinity of the plant. Although basins within Alameda County are under investigation for the potential for carbon sequestration, there are no such sites that have been demonstrated as appropriate for sequestration at this time.

The Air District has found no reason to revisit this analysis based on the further comments it received. The Air District conducted further investigation in light of these comments, and found

[36] Some comments also suggested that the project's greenhouse gas emissions could be lowered by using "Fast-Start" technology. As described in the responses to comments on startup issues (*see infra*, Section VII.C.), Fast-Start technology would actually increase emissions of greenhouse gases from the facility because of the inherently lower energy efficiency of facilities equipped with Fast-Start.
[37] *See* Statement of Basis at pp. 60-61.

further evidence to support its earlier conclusion. At the federal level, the U.S. Department of Energy is in the midst of a three-phase effort to develop an infrastructure and knowledge base to foster commercialization of carbon sequestration technologies.[38] The first phase characterized the potential for CO_2 storage in the U.S. and Canada; the second phase consists of small-scale geological storage tests; and the third phase will conduct large-scale sequestration projects.[39] Injections are expected to begin at some sites as early as spring 2010.[40]

At the state level, Assembly Bill 1925 (Blakeslee, Chapter 471, Statutes of 2006) directed the California Energy Commission "to submit a report to the Legislature containing recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide." To this end, WESTCARB, the West Coast Regional Carbon Sequestration Partnership (funded by the U.S. Department of Energy and the California Energy Commission) issued an initial report in 2008.[41] This report characterized issues associated with carbon capture and sequestration technology and determined areas needing further analysis. A follow-up report will include results of WESTCARB field pilots and foundational data and analysis to support development of an appropriate regulatory framework.[42] This report is planned for 2010 and is not yet available.

The Air District also found several sequestration projects have been proposed in California, although the development of the technology is still in its infancy. For example, in Kern County, Clean Energy Systems is building an oxy-combustion power plant beneath which the WESTCARB partnership will inject 250,000 tons of CO_2 per year for four years.[43] The approximately 50 MW plant and associated CO_2 clean-up, compression, and injection systems are projected to come online in mid-2011.[44] Also in Kern County, Hydrogen Energy International LLC is proposing to build an integrated gasification combined cycle power generating facility.[45] The plant would gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode.[46] The gasification component would capture approximately 90 percent of the CO_2 during

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[38] *See* U.S. Department of Energy, Carbon Sequestration Regional Partnerships (available at: www.fossil.energy.gov/sequestration/partnerships/index.html).

[39] *Id*.

[40] *Id.*

[41] Burton, *et al.*, Geologic Carbon Sequestration Strategies for California, CEC Systems Office Report to the Legislature (2008) at 21.

[42] *See* Burton, *et al.*, *Informing Policy Development for Geologic Carbon Sequestration in California*, Energy Procedia 1 (2009) (hereafter, "Informing Policy Development") at 4,619, available at: www.sciencedirect.com/.

[43] *See* Factsheet for WESTCARB Field Validation Test at 1, (available at: www.netl.doe.gov/publications/proceedings/08/rcsp/factsheets/22-WESTCARB_Large%20Volume%20Sequestration%20Test_PhIII.pdf.)

[44] *Id.*

[45] For the project's website, see www.hydrogenenergycalifornia.com/default.aspx?pageid=1. For California Energy Commission review information, *see* www.energy.ca.gov/sitingcases/hydrogen_energy/index.html.

[46] *See id*.

steady-state operation, which would be transported via pipeline to the Elk Hills Field for CO_2 enhanced oil recovery and sequestration.[47] Commercial operation is expected to begin in 2015.[48] These proposed projects represent promising developments and indicate that carbon sequestration may someday provide a viable alternative for emissions control for power plants. However, its availability for a project such as the proposed facility appears to be even farther off in the future, given that the projects proposed for sequestration, such as the Hydrogen Energy project, all would rely on a fuel that has a higher carbon content in its emissions stream (*i.e.*, a "dirtier" fuel) than natural gas. Research into potential application of carbon capture and sequestration technology to facilities burning natural gas is still in its infancy.[49]

For example, the Energy Commission recently held a workshop to begin considering the feasibility of potential application of carbon capture and sequestration technology to new or retrofitted natural gas-fired combined-cycle power plants.[50] However, these efforts are very preliminary in nature, with the current "Phase 1" efforts amounting to an engineering and economic assessment to identify existing or proposed plants in Pacific Gas and Electric Company's (PG&E) service area that might be outfitted with carbon capture and storage technology. These Phase 1 efforts will conclude with development of a preliminary scope, cost, and schedule estimate for construction of "a pilot-scale (nominally 15–50 Megawatts) technology validation test" applying carbon capture and storage technology to a natural gas-fired combined-cycle power plant in PG&E's service territory. This example illustrates that planning efforts currently underway for potential application of carbon capture and sequestration technology to a natural gas-fired power plant are still in their earliest stages and have not even progressed to pilot-scale testing yet. In light of this, such technology cannot be found to be technically feasible for purposes of a full-scale operation.

To move carbon capture and sequestration projects to the commercial stage will require surface and subsurface site characterization; monitoring and verification of stored CO_2; health, safety and environmental risk assessment and management; and remediation and mitigation planning.[51] These issues need to be addressed through consistent and integrated protocols.[52] According to a recent assessment, "[c]urrently no consensus or standard exists to set criteria for these components that will adequately or even minimally address the potential concerns of operators,

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[47] *Id.*

[48] *See* Revised Application for Certification for Hydrogen Energy California, Vol. 1 (May 2009) at 1-4 (available at: www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/revised_afc/Volume_I/1.0%20Executive%20Summary.pdf).

[49] *See*, *e.g.*, Matthew L. Wald, "A Bid to Cut Emissions Looks Away From Coal", New York Times, October 31, 2009 (available at: www.nytimes.com/2009/11/01/science/earth/01carbon.html?_r=1&scp=2&sq=carbon%20capture&st=cse).

[50] *See* California Energy Commission, "Staff Workshop, West Coast Regional Carbon Sequestration Partnership (WESTCARB): Assessment of Natural Gas Combined Cycle (NGCC Plants with CO_2 Capture and Storage" (announcing workshop held on January 10, 2010); (available at: www.energy.ca.gov/contracts/2010-01-14_WESTCARB_Pre-Proposal_Workshop.pdf).

[51] *Informing Policy Development, supra* note 42, at 4,621.

[52] *Id.* at 4,622.

regulators, and other stakeholders."[53] EPA has proposed federal requirements under the Safe Drinking Water Act (SDWA) that would apply to owners and operators of injection wells that will be used for CO_2 injection for geologic sequestration.[54] The proposed requirements address endangerment to underground sources of drinking water posed by improperly managed geologic sequestration projects.[55] Like the large-scale field pilots, a comprehensive regulatory framework, including health and safety criteria, is still in the very early stages. For these reasons, subterranean sequestration of carbon cannot be considered a feasible control technology for purposes of a BACT analysis at this time.

The Air District also considered the comments' reference to bio-sequestration of carbon in algae-producing ponds. Research has begun on an emerging technology that would use "algae bioreactors" to sequester carbon dioxide emissions. An algae bioreactor would house huge quantities of algae that would use CO_2 captured from a power plant for photosynthesis. Although the technology is potentially promising, it is also in its infancy and is not feasible at this time as an add-on control technology.[56] Moreover, the comment on this point did not provide any information on how the facility could feasibly implement bio-sequestration, it simply referenced the technology and suggested that the Air District study it. The Air District has done so in response to this comment, but disagrees that bio-sequestration is currently feasible control technology that could be required here as part of a greenhouse gas BACT technology review.[57]

For these reasons, the Air District disagrees that subterranean sequestration or bio-sequestration are appropriate BACT control technologies. These are active areas of research and development, however, and the development of carbon capture and sequestration technologies, both geological and biological, will continue to be monitored.

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[53] *Id.*

[54] Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Proposed Rule, 73 Fed. Reg. 43,492 (July 25, 2008). EPA subsequently issued a Notice of Data Availability and Request for Comment that supplements the proposed requirements. *See* 74 Fed. Reg. 44,802 (Aug. 31, 2009).

[55] 73 Fed. Reg. at 43,497.

[56] *See* Leland E. Teschler, "Algae Automation", Machine Design (March 3, 2009), available at: http://machinedesign.com/article/algae-automation-0303.

[57] To the extent that the commenter intended "bio-sequestration" to mean simply using vegetation to remove CO_2 from the atmosphere generally, the Air District disagrees that this approach to addressing greenhouse gas emissions could be considered a BACT control technology. BACT control technologies reduce or remove air pollutants before they are released into the atmosphere. Reducing greenhouse gas emissions from the atmosphere once they have been emitted, for example by planting trees or putting algae in ponds to draw CO_2 out of the atmosphere, is more in the nature of offsets than it is a BACT control technology. The Air District therefore disagrees that requiring a facility to plant vegetation to remove CO_2 as a means of addressing its greenhouse gas emissions could be required in a BACT analysis.

Comment III.B.2. – Evaluation of Non-Fossil-Fuel Fired Electrical Generation Alternatives:

The Air District also received comments stating that it should have evaluated alternative energy production methods that do not rely on fossil fuel combustion, such as hybrid technologies that combine energy sources to improve the overall carbon efficiency of the power plant, requiring co-generation with the project, and changes in project design (*e.g.*, elimination of duct burners, or replacing them with a more efficient microturbine or solar energy collection). The comments claimed that the District should not focus simply on *turbine* efficiency (as opposed to more efficient ways of making electricity without using combustion turbines).

Response: The Air District has considered these comments and is in agreement that the development of non-fossil-fuel electrical generating sources is of critical importance in meeting California's energy needs while at the same time furthering its air quality goals, especially in light of recent advances in the understanding of the problems posed by global climate change. The Air District recognizes, however, that alternative generating technologies are not currently capable of meeting the state's electrical power demand at all times and under all circumstances, and that some fossil-fuel generating capacity is still needed.[58] Determining the most appropriate mix of electrical generation sources under these circumstances is a highly complex engineering and policy exercise that is most appropriately undertaken by the California Energy Commission, the state's expert agency on energy policy matters. The Air District obviously has a supporting role to play in helping the Energy Commission to understand the air quality impacts of its siting decisions and to include appropriate air quality conditions in its licenses. But as an agency, the Air District does not have the expertise nor the authority to determine what type of generation sources are needed, of what capacity, and where. The Air District must therefore necessarily defer to the Energy Commission's decision that the proposed natural-gas fired, combined-cycle facility is the most appropriate alternative for this project. If it would be more appropriate to use wind or solar power to serve the function intended for the proposed Russell City project, the Energy Commission is the agency best suited – and specifically tasked by the California legislature – to make that determination.

Here, the Energy Commission specifically evaluated potential non-fossil-fuel-fired alternatives, such as solar, wind, and biomass, in its licensing proceeding for the Russell City Energy Center. The Energy Commission ultimately rejected those alternatives as not feasible because "they do not fulfill a basic objective of the plant: to provide power from a baseload facility to meet the

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[58] *See, e.g.*, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report prepared by MRW & Associates for the California Energy Commission (available at: www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF); California Energy Commission, *Final Commission Decision, Avenal Energy, Application for Certification* (08-AFC-01), Kings County (Dec. 16, 2009) (hereinafter, "Avenal Energy Commission Decision"), p. 112, Finding of Fact no. 23 ("The addition of some efficient, dispatchable, natural-gas-fired generation will be necessary to integrate renewables into California's electricity system and meet the state's RPS and GHG goals, but the amount is not without limit.") (available at: www.energy.ca.gov/2009publications/CEC-800-2009-006/CEC-800-2009-006-CMF.PDF).

growing demands for reliable power in the San Francisco Bay Area."[59] The Energy Commission rejected wind and solar generating sources because of their inherently intermittent nature, which makes them inappropriate for a generating resource intended to ensure an adequate supply of power in periods when solar and wind sources do not provide power to the grid.[60] The Energy Commission also noted that alternatives like wind and solar involve other environmental trade-offs that can offset the benefits of reduced air emissions. For example, the Energy Commission found that a "wind farm" capable of generating 600 megawatts of power would require 10,200 acres, approximately 690 times the amount of land needed for the Russell City project and associated facilities."[61] The Energy Commission similarly found that a solar thermal project would require approximately 3,000 acres, or over 200 times the amount of land needed for the Russell City project.[62] For all of these reasons, the Energy Commission determined that the better policy choice, taking into account all relevant factors, would be the facility as proposed and not a facility using alternative, non-fossil-fuel generating technology.[63] The Energy

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[59] 2002 Energy Commission Decision, *supra* note 17, at p. 19. The Energy Commission made a further finding in its 2007 Amendment decision that no renewable alternatives would be able to meet the project's objectives. *See* 2007 Energy Commission Decision, *supra* note 16, at p. 21, finding 3. In making this finding, the Commission relied in part upon the detailed analyses that were undertaken in connection with the original licensing proceeding in 2002. *See id*., pp. 20-21.

[60] 2002 Energy Commission Decision, *supra* note 17, at pp. 18-19.

[61] *Id*.

[62] *Id*.

[63] One alternative that the Energy Commission did not consider was coal-fired generating technologies. Some have argued that coal and natural gas should be considered alternatives of one another, and if this approach were taken then coal should be considered as an alternative along with wind, solar and biomass. To the extent that the Energy Commission even considered this issue, it is likely that it did not undertake a considered evaluation of a coal-fired alternative because in most respects natural gas is a far cleaner fuel. For example, the average emissions rate from existing coal-fired generation in the United States has been estimated by U.S. EPA at 2,249 lbs/MWhr of CO_2. (*See* Environmental Protection Agency, *Air Emissions* (hereinafter EPA Air Emissions Summary), available at www.epa.gov/cleanrgy/energy-and-you/affect/air-emissions.html.) Other sources have estimated an average emissions rate over 2,300 lbs/MW-hr. (*See* California Air Resources Board, *Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01* (June 20, 2007), available at: www.arb.ca.gov/cc/ccei/presentations/OOS_EmissionFactors.pdf. Meanwhile, according to U.S. EPA, "[c]ompared to the average air emissions from coal-fired generation, [combustion of] natural gas produces half as much carbon dioxide," or about 1,135 lbs/MWhr. (*See* EPA Air Emissions Summary.) Other estimates put this number as low as 800 lbs/MWhr. (*See* Pace, *Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results*, prepared for Center for Liquefied Natural Gas (Feb. 3, 2009) at p. 13 (available at: www.energy.ca.gov/lng/documents/2009-02-03_LCA_ASSUMPTIONS_LNG_AND_COAL.PDF).) Even the most recent advanced coal generation technologies such as an integrated gasification combined-cycle (IGCC) coal-fired plant, which emits over 1,700 lb/MW-hr, would not come close to the emissions performance of natural gas. (*See id* at 11-12.) Any comparison

Commission also considered biomass such as wood chips or agricultural waste as a fuel source, but found that such an alternative would not be feasible because no biomass fuel source is available in large enough quantities in the vicinity of the project.[64]

The Federal PSD BACT requirement is not designed to intrude upon this analysis by the expert state agency on power generation and supply policy. To the contrary, Federal PSD permitting explicitly contemplates that PSD permitting authorities will defer to other state agencies on siting decisions.[65] The Air District therefore disagrees that it should require a further review of alternative types of projects – even if they would involve fewer emissions – because that type of alternatives analysis is properly within the province of the Energy Commission's siting authority under the Warren-Alquist Act.

The Air District is of course cognizant of its obligation as the Federal PSD permitting authority to provide an independent determination of what the Federal PSD BACT provision requires for a power plant like this one. But the federal BACT framework is clear that it does not require consideration of the use of non-fossil-fuel-fired alternatives, and the Air District therefore could not suggest to the Energy Commission that such alternatives are required by the Federal PSD regulations, regardless of whether there are sound policy reasons to consider them. In determining the Best Available Control Technology for a proposed facility, EPA requires that the Air District examine the best technology for that particular type of facility. EPA requires that the Air District consider the purpose and basic design of the facility, and consider only control technologies consistent with that purpose and basic design. EPA has made clear that the BACT analysis should not include alternative technologies that would require the facility to undergo significant modifications that would alter its fundamental scope, or would change design elements inherent to the facility's purpose, or would call into question the existence of the facility, or would disrupt the applicant's basic business purpose for the proposed facility.[66] Here, non-fossil fuel technologies, such as wind and solar, would not be consistent with the facility's purpose and basic design. To the contrary, they would require a fundamental change in the facility's purpose – generating electric power from natural gas combustion – and would require a complete redesign of the basic elements of the facility. Moreover, changing to such technologies would likely call the existence of the facility into question, because it is far from clear whether wind or solar technologies could be used in lieu of combustion technology to meet the power generation demand the proposed facility will serve, according to the Energy Commission's

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of natural gas and coal as fuels would therefore find that natural gas is by far the preferable alternative.

[64] 2002 Energy Commission Decision, *supra* note 17, at p. 18.

[65] *See In re Prairie State Generating Co.*, PSD Appeal 05-05, *supra* note 6, slip op. at 44; *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 27 n.1 (EAB 1994); *In re EcoEléctrica, LP*, 7 E.A.D. 56, 74 (EAB 1997); *In re Kentucky Utils. Co.*, PSD Appeal No. 82-5, at 2 (Adm'r 1982).

[66] *See generally* NSR Workshop Manual at p. B.13; *In re Prairie State Generating Co.*, *supra* note 6, slip op. at 32; *In re Kendall New Century Dev.*, *supra* note 6, 11 E.A.D. at pp. 50-52 & n. 14; *In re Hillman Power Co.*, 10 E.A.D. 673, 691-92 (EAB 2002); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999); after remand, 9 E.A.D. 1, 31-33 (EAB 2000); *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 29-30 n.8 (EAB 1994); *In re Hawaii Commercial & Sugar Co.*, 4 E.A.D. 95, 99-100 (EAB 1992); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992).

findings discussed above. For all of these reasons, the BACT analysis is not required to consider such alternatives.

The Air District published this explanation and analysis in the Additional Statement of Basis and received no further comment on it.

Comment III.B.3. – Evaluation of Most Efficient Combined-Cycle Combustion Turbine Technology:
The Air District received comments criticizing its assessment that the Siemens-Westinghouse 501F turbines the applicant proposed for the project, which the District found to be 55.8% efficient, are the most efficient equipment available. The comments stated that Siemens' new G-class turbines could be used to achieve a net plant efficiency of 58% and are already in operation at a number of plants. The comments also stated that GE "H Class" turbines can achieve 60% efficiency, and have been in operation in Wales and Japan for some time. Comments also claimed that the proposed Siemens F-Class turbines are at the bottom end of the 55.8-56.5% range from similar turbines as evaluated in the Energy Commission's documents, and the District has not explained why more efficient turbines should not have been required. Some comments also questioned the District's reliance turbine efficiency data from the 2007 CEC proceeding, which they was based on data from the 2002 CEC proceeding and testimony that the information had not changed.

Response: In response to these comments, the Air District has further reviewed the types of gas turbine equipment available for this project to ensure that the facility will use the most efficient equipment. As noted above in Section II.A., the Air District found that recent advances in the Siemens F-class turbines have resulted in increased efficiency over the FD2 turbines that the applicant initially proposed. These FD3 upgrades can achieve a gross efficiency of 56.45% (LHV) for the combined-cycle facility (without duct burning), a small but significant increase over the 55.8% for the FD2 turbines as initially proposed. The Air District has therefore determined that an efficiency of 56.45% is achievable using FD3-equivalent technology, and is basing its revised greenhouse gas BACT analysis on this efficiency level.

Beyond the FD3-equivent technology, the Air District also examined the feasibility and potential emissions performance advantages of using next-generation turbine equipment such as G-Class or H-Class turbines at this facility. For G-Class turbines, this equipment would actually reduce the overall efficiency of the facility and increase greenhouse gas emissions per megawatt of power produced. This is because G-class turbines have a substantially greater power output than F-Class turbines. Thus, in order to build a 612-megawatt combined-cycle power plant as proposed here using G-Class turbines, the Applicant would need to use a substantially smaller steam turbine (143 MW) to provide the equivalent plant output, which is specified at 612.8 MW (net).[67] This would result in an inefficient bottoming cycle and would lower the overall plant

[67] *See* Table, Comparison of Plant Efficiency, 612.8 MW: FD2, FD3, G-Class and Flex 10 Configurations, Prepared by A. Prusi, Calpine, April 2, 2008 (hereinafter, "Plant Efficiency Comparison Table"). Siemens G-class turbines, when initially introduced in 1999, had an output of 235 MW. (*See* E. Bancalari & P. Chan, Siemens AG, *Adaptation of the SGT6-6000G to a Dynamic Power Generation Market*, December 2005, at 12 (available at: www.powergeneration.siemens.com/news-events/technical-papers/gas-turbines-power-

gross efficiency rating to 49.8% (LHV), according to an analysis provided by the Applicant, compared to the 56.4% efficiency rating of the facility using the latest F-Class technology.[68] As a consequence, although the G-Class turbines may be marginally more efficient by themselves, when incorporated into a combined-cycle facility of this size they would result in lower efficiency for the facility as a whole. The Air District has therefore concluded that the use of G-class turbines would not be the top-ranked control technology here (*i.e.*, would not lead to the most efficient plant), and would not constitute BACT.

As for H-Class turbines, that turbine class is not yet demonstrated and commercially available for the 60 Hz electrical power system used in the United States, and is therefore not a feasible control technology for purposes of the BACT analysis. GE does have an H-Class turbine that has been fairly well demonstrated for 50 Hz power systems used in other countries. It installed an initial 50 Hz technology validation project at Baglan Bay in Wales that has been in operation since 2003;[69] and it has a second 50 Hz project in Futtsu, Japan, that began operation in July 2008 (with a second turbine expected to come on-line in late 2009), which GE characterizes as "a key step in the commercial development of [the] H System gas turbine".[70] But GE's H-Class 60-Hz turbine is not as far along in the development process, and the company has only recently installed its first 60-Hz H-class test turbine at the Inland Empire Energy Center in Riverside County, CA, which began operation on January 28, 2009.[71] This project will require extensive testing to ensure that it meets all design specifications and is sufficiently reliable for long-term operations,[72] and cannot be considered an available technology until this validation process is

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plants/index.htm#AdaptationoftheSGT6-6000GtoaDynamicPowerGenerationMarket).) Using two such turbines in a 2x1 configuration would require a 142.8 MW steam turbine to meet a 612.8 MW design capacity (235+235+142.8=612.8). This is a conservative estimate because current G-class turbines are even larger (*see id.*), which would necessitate an even smaller steam turbine and even less overall efficiency.

[68] *See* Plant Efficiency Comparison Table, *supra* note 67.

[69] GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* www.gepower.com/about/press/en/2007_press/121107b.htm; (hereinafter, "GE H-Class Press Release"); Frank J. Bartos P.E., *New, efficient industrial gas turbines coming: Siemens, GE, Full Report* Control Engineering, (August 8, 2008) (available at http://mobile.controleng.com/article/268171-New_efficient_industrial_gas_turbines_coming_Siemens_GE_full_report.php).

[70] Steve Bolze, Vice President-Power Generation, GE Energy, *quoted in* GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* (http://www.gepower.com/about/press/en/2007_press/121107b.htm).

[71] *See* GE H-Class Press Release, *supra* note 69; Frank J. Bartos P.E., *The Hunt for 60%+ Thermal Efficiency*, Control Engineering (August 1, 2008) (available at www.controleng.com/article/CA6584899.html). The specific startup date for the Inland Empire project was provided by the applicant in communications in April of 2009.

[72] *See generally* Frank J. Bartos P.E., *New, efficient industrial gas turbines coming: Siemens, GE, Full Report* Control Engineering, (August 8, 2008) (available at www.controleng.com/article/CA6584786.html?rssid=274) ("Extensive, predefined testing is necessary to ensure that turbine performance meets design specs, along with reliable, long-term operation associated with power systems. With several different technology levels being

completed. As the Energy Commission noted in approving the installation of these H-Class turbines, the "install[ation], operat[ion] and test[ing of] this initial Frame 7H machine [is an] essential step in the development and marketing of this new product[.]"[73] The Air District has therefore concluded that H-Class turbines are not an available technology at the present time for this type of project.[74]

Based on this review, the Air District concludes that there is no other commercially available generating technology that would meet the needs of this project that would have a greater energy efficiency than the upgraded "FD3" turbines the applicant has proposed for use at the facility. The Air District also compared the 56.4% efficiency of this facility with other similar facilities in California that have been recently permitted or are currently undergoing review, and found it to be higher than any other comparable facility (with the exception of the Inland Empire Frame 7H demonstration turbines addressed above). The results of this comparison are summarized in Table 1 below.[75]

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validated, the long development cycle needed for these turbines—from first firing through commercialization—becomes evident.").

[73] Memorandum, *Inland Empire Energy Center Power Project (01-AFC-17C) Staff Analysis Of Proposed Modifications To Change To GE 107H Combined-Cycle Systems, Increase Generation and Add Additional Laydown Areas*, From Connie Bruins, CEC Compliance Division Manager, to Interested Parties (Jun. 8, 2005) (hereinafter "Inland Empire Energy Center Staff Analysis Memorandum"), at p. iii. (available at: www.energy.ca.gov/sitingcases/inlandempire/compliance/2005-06-10_FINAL_ANALYSIS.PDF.) The Commission staff also observed that "as with any emerging technology, the proposed project involves a heightened risk of underperformance." (*Id.* at p. 2.)

[74] The Air District also examined Siemens technology in addition to GE. Siemens is also developing an H-Class product, but it is farther behind than GE. Siemens has installed a 50 Hz test project in Irsching, Germany, but it is currently validating the turbine in simple-cycle mode, with build-out of a combined-cycle configuration not planned until 2009-2011. (*See* Frank J. Bartos P.E., *Largest Gas Turbine: 2,838 Sensors, 90 GB Data Per Hour of Testing* Control Engineering, (February 13, 2009) (available at www.controleng.com/article/ca6637328.html?nid=2488&rid=1768760).) Siemens does not yet have a 60-Hz application installed anywhere in the world.

[75] The information in Table 1 was taken from documents on the Energy Commission's website at www.energy.ca.gov.

Table 1: Comparison of Thermal Efficiency of Similar Combined-Cycle Power Plants

Facility	CEC Application Date	Facility Size (MW)	Thermal Efficiency (LHV)
Colusa Generation Station	11/6/2006	660	56%
Blythe Energy Project Phase II	2/19/2002	520	55-58% (est.)
Lodi Energy Center	9/10/2008	255	55.6%
CPV Vaca Station Power Plant	11/18/2008	660	55%
Victorville 2 Hybrid Power Project	2/28/2007	563	52.7% (w/ duct burn) 59.0% (thermal solar)
Avenal Energy Power Plant[76]	2/21/2008	600	50.5%
Palomar Energy Project	8/2003	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)
SMUD Consumnes Phase I	9/13/2001	500	55.1%

For all of these reasons, the Air District has determined that the 56.4% thermal efficiency proposed for the Russell City Energy Center is the best efficiency performance achievable from commercially available systems for a 600 MW combined-cycle power plant.

The Air District published this revised analysis of what equipment constitutes the most efficient for this type of facility in its August 2009 Additional Statement of Basis, and received little further comment. One comment the District did receive questioned how long ago the existing facilities that the Air District examined in its initial analysis of BACT technology for greenhouse gases were built. The Air District disagrees that the age of the facilities it evaluated is relevant to the BACT analysis. A rigorous BACT analysis should consider any and all similar facilities regardless of age to identify the best emissions performance that is being achieved. One generally assumes that newer facilities will have lower emissions, but it could certainly be possible that an older facility actually performs better. In such a case, it would be appropriate to base a BACT limit on the emissions performance achieved by the older facility. The Air District therefore disagrees that the age of the facilities it reviewed is relevant. What matters is that the District identified the best emissions performance currently achievable. This comment does not provide any suggestion that the Air District did not properly do so, as it did not identify any newer or cleaner facility that was omitted from the District's analysis. The Air District remains confident that its BACT analysis reflects the best performance achievable today by current, state-of-the-art generating equipment.

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[76] With respect to Avenal, one commenter stated that this proposed facility would be able to achieve a CO_2 emissions rate of 499.7 lb/MW-hr, but its calculation was based on estimated emissions at 50% load ("Case 12" in the table referenced by the commenter). At full load, emissions would be over 900 lb/MW-hr (using "Case 1") and a nominal power output of 600 MW based on the documentation cited by this commenter.

C. Expression of Greenhouse Gas BACT Emissions Limits In Permit Conditions

Comment III.C.1. – Evaluation of BACT Emissions Performance Standard for Combined-Cycle Combustion Turbines:

The Air District initially proposed to establish an 1100 lb/MW-hr greenhouse gas BACT standard based on the most stringent regulatory mandates that have so far been adopted for electrical generation. (*See* Statement of Basis at pp. 58-59.) The District received a number of comments during the first comment period that criticized the use of this 1100 lb/MW-hr standard as a BACT limit. These comments raised a number of related points in this regard.

- *Linkage Between lb/MW-hr CO_2 Emission Rates and Thermal Efficiency:* Some comments questioned the District's analysis of the range of lb/MW-hr CO_2 emissions performance levels among various turbines in the context of thermal efficiency. These comments referred to the fact that the BACT technology analysis was explained in terms of turbine thermal efficiency; yet when selecting the BACT performance level BACT was stated in terms of mass emissions per unit of power output. The comments stated that the District had not explained how the range of turbine thermal efficiency percentages evaluated relates to the range of lb/MW-hr CO_2 emissions levels (although they stated that they presumed that the higher lb/MW-hr CO_2 emissions levels correspond to the less efficient turbines).
- *Use of Emissions Standard from SB 1368:* Comments also noted that the proposed 1100 lb/MW-hr permit limit was taken from SB 1368, and that it was developed in that context to accommodate existing facilities with older, higher-emitting equipment as well as new plants. These comments claimed that this number can therefore at most be a floor for setting a BACT limit, and that it is not a measure of the best achievable performance. The comments also claimed that the number was intended to apply to facilities state-wide, and it is not a case-specific determination of what a particular facility can achieve as required by BACT.
- *Data Showing Achievable Emissions ~800 lb/MW-hr:* The comments stated that emissions data from new turbines show that current equipment should be able to achieve emissions as low as 800 lb/MW-hr, and one cited a CEC paper stating that 800 lbs CO_2/MW-hr is an emissions rate that the most efficient modern combustion turbine combined cycle plant can achieve. The comments contended that the BACT limit should be set no higher than this 800 lb/MW-hr level. Comments also stated that the District should look at the best achievable performance level of all turbines, including new turbines, and not limit its review to turbines that were built several years ago. Comments also claimed that the District considered emissions data from only one year of operation from only two facilities, and should conduct a broader review.
- *Justification For Compliance Margin:* The comments also criticized the District's claim that the BACT limit should be set at 1100 lb/MW-hr limit in order to provide a compliance margin. These comments noted that 1100 lb/MW-hr is significantly higher than the emissions measured from the comparable facilities that the District examined (Metcalf and Delta). They asserted that the District should explain in more detail the need for a compliance margin and also the necessary magnitude of the margin. They claimed that the District should explain what foreseeable operating conditions might affect emissions performance, and provide data showing how much of a compliance

margin these conditions would warrant. One comment suggested that the District should also consider a multi-tiered limit that would apply differently to different operating conditions.

- *Justification for Heat Input Limit:* One comment framed its objection in terms of the heat input limit that the District derived from the 1100 lb/MW-hr emissions rate. The comment noted that the corresponding heat input rate the District used as a BACT limit – 2944.3 MMBtu/hr – is 35% higher than the rated maximum for the proposed turbines. The comment objected that this approach would allow turbines with a much lower efficiency than the 55.8% level achievable by these turbines. The comment claimed that this limit has no connection to actual emission rates achievable by such sources.
- *"Output-Based" Limit to Address Efficiency Changes Over Time:* Several comments objected to the District's proposal to express the BACT limit for greenhouse gases only as a limit on turbine heat input. These comments claimed that instead of limiting heat input, the District should impose a limit on the mass of CO_2 emitted per MW-hr directly. The comments claimed that if the limit is imposed on heat input only, emissions on a lb/MW-hr basis could rise if turbine efficiency declines because of maintenance issues, equipment modifications, or other reasons. One comment cited the *Steel Dynamics* EAB decision for the proposition that a BACT limit needs to ensure compliance on a continual basis over all levels of operation.

Response: In response to these comments, the Air District reevaluated the BACT emissions limits it initially proposed, and upon further consideration agrees that 1100 lb/MW-hr would not be an appropriate BACT limit for greenhouse gas emissions. Instead, the Air District is imposing a lower BACT emissions limit for greenhouse gases in the permit, and is also imposing an "output-based" requirement for periodic compliance testing to ensure that the plant maintains the BACT efficiency standard over time.[77] In particular, the Air District has adjusted its BACT determination in response to the comments it received as follows.

- First, the Air District has focused its analysis of what emissions performance is achievable by generating equipment with a thermal efficiency at a BACT level of 56.4%. The Air District agrees with the comment that simply looking at lb/MW-hr numbers reported in the ARB database does not necessarily tie the analysis into thermal efficiency, which is the basis for the District's BACT analysis. Tying the analysis of the achievable numerical BACT emissions limitation to specific data about expected turbine performance is intended to address this issue. As explained below, for purposes of establishing an enforceable numerical efficiency limit, the Air District has used heat input per unit of power output (in MMBtu/kWhr) as the appropriate metric for establishing the BACT limit because the objective, industry-standard method for measuring efficiency uses that metric.

[77] The Air District published its further analysis and its revised BACT limits in its August 2009 Additional Statement of Basis and revised draft permit. The Air District did not receive any comments providing any reason why this revised approach would not be appropriate under the PSD BACT requirements, and so the Air District is finalizing the BACT limits essentially as proposed in August of 2009. The District is responding to all of the comments from both the first and second comment periods in this document.

- Second, the Air District agrees that using the 1100 lb/MW-hr number established for purposes of SB 1368 as a performance standard for all turbines does not necessarily capture the best performance achievable by the most efficient turbines available for use in new projects, on which a BACT analysis should be based. Instead, the District has analyzed the greenhouse gas emissions that can be achieved by state-of-the-art FD3 class turbines, as noted above. The Air District has determined that the BACT emissions rate should be based upon a best achievable design base heat rate of 6852 Btu/kWhr (which is approximately equivalent to an emissions rate of 792-815 lb/MW-hr, depending on which emissions factor is used), with a reasonable compliance margin of a little over 12% to account for various factors that may make the best design performance unachievable during all operating scenarios over the life of the equipment. This compliance margin is based on a thorough analysis the various elements of turbine operation that may reduce turbine efficiency over time and thereby increase greenhouse gas emissions per unit of power output, as discussed in detail below.
- Third, the Air District agrees that the BACT limit as expressed in the permit needs to be "output based", instead of just limiting greenhouse gas emissions limits, in order to take into account the potential that maintenance issues or other concerns may lead to declining efficiency. The Air District is therefore requiring both mass emissions limits based on the amount of greenhouse gas emissions expected for combined-cycle turbines with this level of thermal efficiency, plus periodic compliance tests to ensure that the efficiency remains within the established BACT levels. The Air District is basing the efficiency compliance test on an ASTM standard that measures heat rate per power output, because it is a well-accepted engineering standard with objectively-defined measurement standards.

By adjusting its approach to the greenhouse gas BACT issue in this way, the Air District is imposing BACT permit limits that are based on the best achievable thermal efficiency performance of available equipment, with a reasonable and documented compliance margin to make sure the limits are as stringent as possible and still achievable across all operating scenarios. This revised approach also includes continuous short-term and long-term emissions monitoring as well as periodic efficiency monitoring to ensure that BACT performance does not unreasonably degrade over time because of maintenance lapses or similar concerns.

The District's detailed analysis in each of these areas in response to these comments is set forth below.

1. Conceptual Overview of Proposed Numerical Greenhouse Gas BACT Limits

The Air District is finalizing the Federal PSD Permit with two interrelated numerical BACT emissions limits for greenhouse gases. First, based on the Air District's technological analysis outlined above and in the District's two Statement of Basis documents, the Air District is imposing numerical greenhouse gas mass emissions limits based on the emissions expected from the state-of-the-art FD3 generating equipment. The mass emissions limits are based on the maximum rated heat input capacity of the combustion turbines and HRSG duct burners needed to produce the power generation demand that the facility has been designed to serve. Every unit of heat input generates a known amount of greenhouse gas emissions, and so the Air District is imposing greenhouse gas mass emissions limits based on this heat input capacity, on an hourly, daily, and annual basis. The heat input and greenhouse gas emissions limits the Air District is imposing are set forth in Table 2 below.

Table 2 - Heat Input and Greenhouse Gas Emissions Limit Summary

Averaging Period	Heat Input Limit (MMBtu)	Greenhouse Gas Emissions Limits (metric tons CO_2E)			
		CO_2	CH_4	N_2O	CO_2E
1-Hour	4,477.2	242	0.08	0.14	242
24-Hour	107,452.0	5,797	2.03	3.33	5,802
Annual	35,708,858.0	1,926,399	675	1,107.48	1,928,182

These heat input and mass emissions limits ensure that the facility's turbines and HRSG duct burners will not use any more natural gas, and not have any more greenhouse gas emissions, than the Air District has determined is necessary to meet the design power generation capacity. As described in detail below, the heat input and greenhouse gas emissions will be monitored in real time using natural gas usage information, which provides a very accurate indication of these parameters.

Second, the District is also imposing an "output-based" efficiency limit that takes into account the amount of power generated by the facility, in order to address the concern raised in comments that simply specifying maximum heat input and corresponding greenhouse gas output limits fails to address the potential that turbine efficiency may decline to the point where it no longer reflects BACT. The District is therefore imposing a minimum turbine efficiency requirement, expressed as MMBtu of heat input per megawatt of power output, that the facility will be required to achieve. The facility will be required to conduct annual compliance tests in which heat input and power output are measured to a high degree of accuracy, and will be required to ensure that gas turbine heat input remains below 7,730 Btu/kWHr (HHV), a rate equivalent to generating a minimum of one megawatt of power per 7.73 MMBtu of natural gas burned.

The District is imposing this 7,730 Btu/kWHr (HHV) efficiency limit as the lowest heat input rate that can be reasonably assured under all operating scenarios. As outlined below, the limit is based upon the design efficiency of the 56.4% thermally-efficient FD3-equivalent combustion turbines[78] that the Air District has concluded are the BACT technology for a nominal 600-megawatt natural-gas fired combined-cycle electrical generating facility. This value, known as the "Design Base Heat Rate" for the facility, is 6,852 Btu/KW-hr (HHV), and reflects the thermal efficiency that the facility is designed for. To ensure that the numerical BACT efficiency limit reflects a reasonable margin of compliance, the District has evaluated the factors that could reasonably be expected to degrade the theoretical design efficiency of the turbines and increase the heat rate (*i.e.*, cause more fuel to be required to produce a megawatt of power). The Air District has considered a number of factors in this regard as explained in detail below, including (i) a reasonable design margin of 3.3% to reflect that the equipment as actually

[78] The combustion turbine equipment on which the BACT heat rate analysis was based included the FD3 upgrades discussed above.

constructed and installed may not fully achieve the assumptions that went into the design calculations; (ii) a reasonable performance degradation margin of 6% to reflect reduced efficiency from normal wear and tear on the equipment between major maintenance overhauls; and (iii) an additional 3% degradation margin based on additional wear and tear caused by variability in the operation of the auxiliary plant equipment that will be powered by the turbines, including the natural gas compressors and water recycling system. These potential degradation factors are an unavoidable aspect of building and operating the facility, consistent with best engineering practices, and the ultimate BACT limit needs to account for them to ensure that it is achievable over all operating scenarios. Applying these potential degradation factors to the Design Base Heat Rate, the Air District has concluded that the appropriate numerical Greenhouse Gas BACT heat input efficiency limit for this equipment is 7,730 Btu/kWHr (HHV). The Air District is imposing this limit as an enforceable not-to-exceed permit limit, along with appropriate monitoring and requirements.

In conducting this analysis, the Air District has also been mindful that under normal circumstances the establishment of a numerical BACT permit limit would often involve a review of permit limits imposed at other facilities and of compliance monitoring data required under such permits. In this case, however, no facility the Air District is aware of has ever been subject to an enforceable BACT limit on its emissions of greenhouse gases; nor has any facility, to the Air District's knowledge, been subject to an enforceable limitation on its efficiency (heat rate per kW-hr of power output). Because this represents a "first of its kind" limitation in an air permit, there is little relevant performance data which might provide a basis for concluding that a lower Heat Rate Limit can consistently be met over time. The Air District is therefore using this approach based on reasonable technical assumptions of what the facility can achieve, rather than on actual permit limits or compliance monitoring data from other similar facilities. An enforceable BACT limitation must be set at a level that the facility can achieve for the life of the facility, including as its equipment ages and incurs anticipated degradation. At the same time, the Heat Rate Limit the Air District is imposing is stringent enough to ensure that the facility operator will not be able to allow the equipment to incur undue efficiency degradation through deferral of necessary maintenance such that the assumptions which supported this BACT determination are no longer valid.

2. Derivation of Numerical Greenhouse Gas BACT Limits

<u>Greenhouse Gas Mass Emissions Limits</u>: The Air District calculated the appropriate heat-rate limit and mass emissions rate limits using the maximum heat input capacity of gas turbines and duct burners combined (*i.e.*, maximum plant capacity). The facility's maximum heat input capacity is 4,477.2 MMBtu per hour; 107,452.0 MMBtu/day; and 35,708,858.0 per year. (*See* Proposed Permit Conditions 13, 14 & 15.) The Air District then calculated corresponding mass emissions rates for CO_2, CH_4, N_2O, and CO_2E using established emissions factors. For CO_2, emissions were calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, emissions were calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E was calculated by applying a global warming potential multiplier of 21 and 310 for CH_4 and N_2O, respectively, based upon the Air Resources Board's mandatory reporting

rule.[79] The associated mass emissions limits are outlined in Table 2 above on an hourly, daily and annual basis.

Heat Rate Efficiency Limit: To determine the appropriate heat-input efficiency limit, the Air District started with the turbines' Design Base Heat Rate[80] and then calculated a reasonable compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions as noted above.

- ***Net Design Base Heat Rate – 6,852 Btu/kWhr:***

The turbines' Design Base Heat Rate is 6,852 Btu/kWhr (HHV), based on operation of both combustion turbines with no duct firing, corrected to ISO conditions.[81] (For comparison with a pounds-per-megawatt-hour efficiency rating, this is between 792.9 and 815.5 lbs/MWhr, depending upon which CO_2 emissions factor is applied.[82]) This represents what the plant (at the design stage) is expected to achieve when it is new and clean; it does not represent what it will achieve over time as the equipment incurs degradation between major maintenance overhauls. It also does not represent the equipment manufacturer's guaranteed levels of performance.

Note that this Design Base Heat Rate of 6,852 Btu/kWhr (HHV) without duct firing and 6,970 Btu/kWhr (HHV) with duct firing reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant.[83] The total auxiliary load for this facility is 21.1 MW without duct firing or 24 MW with

[79] The Air District would also note that it is following the convention of stating emissions of greenhouse gases in terms of "CO_2-equivalents" (CO_2E), which, for this source, include emissions of methane (CH_4) and nitrous oxide (N_2O) as well. These two pollutants have a higher "global warming potential" than CO_2, reflecting their relative propensity to trap solar radiation within the Earth's atmosphere that would otherwise be reflected back into outer space and thereby contribute to global warming. The emissions factors and global warming potentials for N_2O and CH_4 are specified by the Air Resources Board's mandatory reporting rule.

[80] Electric generating facilities typically measure their efficiency in terms of the "heat rate", which is the energy content of the fuel, in British thermal units (Btu), that it takes to generate a kilowatt-hour (kW-hr) of electric power to the grid.

[81] Russell City Energy Center Heat Balance Diagrams.

[82] The lower and higher figure reflect application of the emissions factors for CO_2 applicable under U.S. EPA's Climate Leaders program – 115.6 lb/MMBtu – and the Part 75 Acid Rain Monitoring Program, 118.9 lb/MMBtu. Other relevant emissions factors include the California Climate Action Registry's factor of 116.9 lb/MMBtu and the Air Resources Board's mandatory reporting rule, which applies emissions factors for CO_2 between 116.5 and 120.5 lb/MMBtu of natural gas, depending upon the Btu content of the gas stream.

[83] This auxiliary load includes power for the facility's recycling of wastewater from the adjacent City of Hayward's wastewater treatment plant. This system will recycle roughly 4 million gallons of water a day in the facility's operations instead of having to obtain it from other sources; and will use a "Zero Liquid Discharge" system so that none of that wastewater will be discharged to the Bay. The facility also will include a "Low Noise/Plume-Abated" cooling

duct firing.[84] Accounting for this auxiliary load would result in a "gross" Design Base Heat Rate of 6,743 Btu/kWhr (HHV) when duct firing is not occurring, which would result in emissions between 780.3 and 802.5 lbs/MW-hr of CO_2E, depending upon which emissions factor is applied for CO_2. When duct firing is occurring, the "gross" Design Base Heat Rate would be 6,868 Btu/kWhr (HHV), or between 794.7 and 817.4 lbs/MWhr of CO_2E.

- ***Installed Design Base Heat Rate – 7,080 Btu/kWhr:***

While the Design Rate Heat Rate reflects what the engineers aim to achieve in designing the facility, design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation. According to information provided by the Applicant, a design margin of up to 5% is typical in the commercial terms for the engineering, procurement and construction contracts for a combined-cycle power plant. Normally the performance guarantees from the combustion and steam turbine original equipment manufacturers and the contractual terms require demonstration that the project, as constructed, achieves the design output and heat rate, subject to a plus or minus 5% margin. For example, if the tested output is more than 95% of the guaranteed output, or the tested heat rate is less than 105% of guaranteed heat rate, the original equipment manufacturer and engineering, procurement and construction contractor can declare substantial completion and pay liquidated damages to compensate for the performance shortfalls. The design margin also reflects some tolerance for uncertainties associated with the plant's auxiliary load – such as the potential variance between assumptions about the amount of load that will be required to conduct treatment and evaporation of the City's waste water within the facility – and actual experience. Adding this 3.3% design margin to the Design Base Heat Rate results in an Installed Base Heat Rate of 7,080 Btu/kWhr (HHV), assuming dual unit operation without duct burner firing, corrected to ISO conditions.

- ***Degraded Base Heat Rate – 7,730 Btu/kWhr:***

To establish an enforceable BACT condition that can be achieved over the life of the facility, the Air District also must account for anticipated degradation of the equipment over time between regular maintenance cycles.

For the gas turbines, the Air District is basing its analysis on a 48,000-operating-hour degradation curve provided by Siemens, which reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5.2%.[85] According to combustion turbine manufacturers, anticipated degradation in heat rate of

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tower, which will consume additional load due to use of recycled waste water. These are important environmentally beneficial aspects of the project.

[84] *See* Russell City Energy Center Heat Balance Diagrams.

[85] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10, July 15, 2008, Figure 3 "Degradation Effect on Gas Turbine Heat Rate*"* TT-DEG-76.

the gas turbines alone can be expected to increase non-linearly over time. The degradation curves relied upon in this analysis describe the amount of "recoverable" and "non-recoverable" degradation. The former includes degradation that can be recovered through compressor water washing, filter changes, instrumentation calibration, and auxiliary equipment maintenance. The latter includes degradation that cannot be restored upon a maintenance overhaul.

The 48,000-hour maintenance interval is based upon Siemens' recommendations, which provide detailed formulae for determining when the equipment should undergo certain inspection and maintenance activities, based upon the accumulated total for both "Equivalent Baseload Hours" and "Equivalent Starts".[86] By calculating Equivalent Baseload Hours and Equivalent Starts, the facility operator accounts for the specific operating conditions and events experienced by the facility that may impact the equipment's performance. These include the difference between baseload and peak firing hours and the impacts caused by instantaneous load changes (*i.e.*, outside of the expected ramp rate).

The original equipment manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, because the projected 5.2% degradation rate represents the *average*, and not the maximum or guaranteed, rate of degradation for the gas turbines, the Air District has determined that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate. A slightly higher than average expected degradation is justified for purposes of developing an enforceable emissions limit here, given the limited operational experience of the new FD3-level turbine technology. Adding this 6% degradation factor to the facility's "Installed Base Heat Rate" of 7,080 Btu/kWhr (HHV) (*i.e.*, the projected heat rate of the equipment in its original condition, after accounting for a predicted 3.3% design margin) results in a potential heat rate of 7,505 Btu/kWhr (HHV) (without duct firing).

Finally, in addition to the heat rate degradation from normal wear and tear on the turbines, the Air District is also providing a reasonable compliance margin based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). These other elements include the following:

- *Variability in Natural Gas Pressure:* The facility needs to bring the natural gas burned in the turbines up to a pressure of 500 psi, and uses gas compressors to do so because the natural gas supplied to the facility is delivered at a lower pressure. According to data from PG&E, the natural gas supplier, the delivery pressure may fluctuate between 170 and 355 psi (or between 250 and 410 psi with upgrades to the natural gas line).[87] Because of the variability in delivery pressure, the gas compressor engines may have to cycle up and down, which can

[86] Siemens Power Generation, Inc., Service Bulletin 36803, *Combustion Turbine Maintenance and Inspection Intervals*, Revision No. 10, October 7, 2004.
[87] Letter, Rodney Boschee, Pacific Gas & Electric, Wholesale Marketing & Business Development, to Chris Delaney, CPN Pipeline Company, subject: Calpine Russell City Energy Center, December 2, 2008.

result in increased wear and tear on the engine and decreased fuel efficiency. This would increase auxiliary load on the facility and reduce overall plant efficiency.

- *Variability in Natural Gas Quality:* In addition to changes in natural gas pressure, the gas supply for the facility may also experience substantial variation in the quality of the natural gas (in terms of its chemical constituents). This can further exacerbate degradation of the gas turbines, in the same way that using low-quality gasoline can affect an automobile's performance.
- *Variability in Cooling Water Quality:* The facility's water recycling system will treat approximately 4 million gallons per day of waste water from the City of Hayward's adjacent treatment plant for use in the plant's operations. Data from the water treatment plant shows a substantial degree of variability in the water quality, which in some cases may require additional recycling of the water supply prior to its use by the facility.[88] The additional recycling would require greater load to conduct such treatment and could result in accelerated degradation of various components of the water treatment system, including pumps and rotating equipment. The same is true of the evaporator and Zero Liquid Discharge system, as well as of the plume-abated cooling towers.
- *Degradation in Turbine Exhaust Flow:* The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow of 3.75% over the 48,000 hour maintenance cycle.[89] This degradation in exhaust flow will result in a direct reduction in the ability of the steam turbine to generate power, which will further degrade the plant's overall efficiency. While degradation in the exhaust flow is expected to be partially offset by degradation in exhaust temperature (which rises over the maintenance cycle)[90], this offset will not make up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow.
- *Degradation in Steam Turbine Performance:* Degradation in the performance of the heat recovery boilers and steam turbine is also expected to occur over the course of a major maintenance cycle.
- *Degradation in Gas Turbine Performance:* The influence of the bay-side environment on the air inlet filter may cause inlet air pressure to be reduced, which would further degrade the performance of the gas turbines.

The Air District found little documentation on which to base a specific numerical estimate of exactly what the efficiency impacts would be from these affects, in part because regulatory agencies have not had to undertake analyses in this area before. Without usable precedents or documentation regarding the precise potential for degradation from these issues, the Air District has used its best engineering judgment to assess how much additional degradation should be

[88] *See* City of Hayward Wastewater Treatment Plant water monitoring data, November 1, 2008 – March 20, 2009; Summary data, *Reclaimed Water Project-2008, Final Clarifier* for sample dated April 16, 2008.
[89] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10, July 15, 2008, Figure 4 "Degradation Effect on Gas Turbine Exhaust Flow," TT-DEG-77.
[90] *Id*., EC-93208-R10, July 15, 2008, Figure 5, "Degradation Effect on Gas Turbine Exhaust Temperature" TT-DEG-78.

anticipated. The Air District believes in its engineering judgment that an additional 3% degradation is a reasonable and appropriate estimate under the circumstances, taking into account the fact that the limits being imposed based on this estimate will be enforceable, not-to-exceed permit conditions.

The Air District published this analysis and its proposed turbine efficiency standard for the facility in the Additional Statement of Basis and invited further review and comment from the public. The Air District received comments during the second comment period noting that for the greenhouse gas BACT determination, the District is allowing a compliance margin of approximately 9% above the design efficiency of the proposed facility. The comments questioned the basis for this compliance margin. In response to this comment, the Air District refers to the analysis outlined above explaining how its compliance margin was derived. The Air District determined that a 3.3% design margin was appropriate to account for uncertainties associated with how the plant will function as actually constructed, compared with its design on paper. The Air District then determined that a further 6% degradation margin was appropriate to take into account the normal decline in efficiency that occurs over the life of the equipment between maintenance intervals. The Air District then determined that a further 3% margin was appropriate to account for potential degradation associated with various uncertainties regarding facility operation, such as variation in natural gas pressure and quality, variability in cooling water quality, and so forth. The Air District notes that the comments did not point to anything specific in this analysis that they suggested was inappropriate. Based on this analysis, the Air District believes that the plant efficiency standard it derived is the most stringent standard that the facility will reasonably be able to achieve during all anticipated operations.

3. Implementation of Numerical Greenhouse Gas BACT Limits In Permit Conditions

Finally, the Air District is implementing these greenhouse gas BACT limits as enforceable permit conditions, with appropriate monitoring and recordkeeping. For the heat-input and GHG mass emissions limits, the facility will be required to demonstrate compliance by monitoring its fuel usage on a real-time basis, and then calculating heat-input and mass emissions based on the fuel usage. For CO_2, mass emissions will be calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, mass emissions will be calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E would be calculated by multiplying CH_4 and N_2O emissions by their respective global warming potentials of 21 and 310, based upon the Air Resources Board's mandatory reporting rule, and then adding them to CO_2 emissions.[91] The facility will be required to maintain records of its heat input and mass emissions monitoring data in order to ensure compliance.

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[91] For purposes of assuring consistency with existing reporting regimes for greenhouse gas emissions, it makes best sense to align monitoring and reporting requirements in the Federal PSD Permit with these prevailing methods for calculation and inventorying of greenhouse gas emissions.

For the turbine efficiency limit (the 7,730 Btu/kWhr heat-rate limit), the Air District is requiring compliance testing to demonstrate compliance within 90 days after the end of the commissioning period (as defined in the permit) and annually thereafter to ensure that efficiency is maintained at a BACT level. Under this periodic compliance test requirement, the facility will be required to perform a "Heat Rate Performance Test" using the industry-accepted method for heat rate and capacity testing, the American Society of Mechanical Engineers (ASME) Performance Test Code on Overall Plant Performance (ASME PTC 46-1996)). This test includes objective parameters that will ensure consistent and reliable reporting of actual turbine efficiency, and it is the accepted industry standard test for this purpose. The facility will be required to conduct the test at baseload (*i.e.*, full capacity), without duct firing. The facility will be required to submit a test plan to the Air District for its review and approval at least thirty (30) days in advance of the proposed test. The test will consist of three one-hour test runs, and the results of each test run will be averaged and then corrected back to ISO conditions of:

- Ambient Dry Bulb Temperature: 59^{o}F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,866 Btu/lb
- Fuel HHV/LHV Ratio: 1.1099

To determine compliance with this condition, the result of this test will be compared to the Heat Rate Limit of 7,730 Btu/kWhr (HHV).

These compliance monitoring requirements will ensure compliance with the greenhouse gas limits in the permit. The Air District also considered whether to require the facility to use a Continuous Emissions Monitor (CEM) to measure greenhouse gas emissions directly (as CO_2), but concluded that calculating emissions from heat input is preferable. Unlike some other pollutants such as NOx or carbon monoxide whose formation is heavily dependent on conditions of combustion and/or performance of add-on emissions controls, greenhouse gases are a direct and unavoidable byproduct of the combustion process. The amount of carbon within the fuel will all ultimately be emitted as greenhouse gases in a manner that is easily determined using well-established emissions factors. One can therefore determine with great accuracy what greenhouse gases are being emitted by measuring the amount of hydrocarbon fuel being burned (measured as heat input). For this reason, the test methods for measuring heat rate and capacity can achieve an accuracy of ±1.5%,[92] which is better than the relative accuracy of CEMs which typically ranges as high as ±10%.[93] The Air District is therefore requiring surrogate monitoring for greenhouse gas emissions using heat rate instead of a CEM.

The Air District also considered whether it would be possible to monitor thermal efficiency on a continuous basis in terms of emissions (or heat input) per unit of power output, but found that it

[92] American Society of Mechanical Engineers (ASME), *Performance Test Code on Overall Plant Performance*, (PTC 46-1996), December 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to steam generator").

[93] *See, e.g.*, 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.").

would not be feasible to measure efficiency in this manner on a continual basis in any meaningful way. Measuring efficiency with a high degree of accuracy requires expertly-administered test procedures as set forth in the ASME PTC 46 standard, and it is not feasible to require this testing methodology to be implemented at all times of facility operation. Moreover, measuring efficiency by comparing heat input to power output would not be feasible during periods such as startup, shutdown, or tuning when no power is being produced for the grid. There will be heat input during this period, but with no power output the denominator in the pounds-per-megawatt-hour efficiency measurement will be zero. And finally, thermal efficiency is unlikely to experience major ups and downs over time. Unlike NOx or CO, which could fall out of compliance rapidly if good combustion conditions are not maintained or if an add-on control device fails, thermal efficiency is likely to degrade relatively slowly over time.[94] A one-day snapshot of turbine efficiency from a periodic compliance test is therefore likely to be relatively representative of efficiency over a longer time frame. For all of these reasons, the Air District is requiring demonstration of compliance with the heat rate BACT limit through a periodic compliance test, not continuous monitoring. The Air District is imposing an annual test requirement, which is the typical test frequency the District requires in periodic monitoring situations such as this. Based on the performance degradation documentation the Air District has reviewed, annual compliance testing is an appropriate testing frequency for this type of permit limit.

D. Greenhouse Gas BACT Analysis for Other Equipment

Comment III.D.1. – Greenhouse Gas Emissions from Emergency Firepump Diesel Engine and Circuit Breakers:

The Air District received comments stating that it should undertake a BACT analysis for greenhouse gas emissions from other equipment at the facility, such as the emergency backup diesel generator and the circuit breakers which the comments stated use SF_6, a greenhouse gas.

Response: The Air District disagrees that a BACT analysis for greenhouse gas emissions for these sources is required by the Federal PSD Regulations. As noted above, EPA has made clear that greenhouse gases are not "subject to regulation" (at least not at this point in time), and so they are not subject to Federal PSD Review as a legal matter. That said, the Applicant has voluntarily requested that the Air District conduct a BACT review of greenhouse gas issues and has agreed to take voluntary greenhouse gas BACT limits imposed by the Air District as part of its permit conditions. To the extent that the Air District is conducting a greenhouse gas BACT analysis for the facility voluntarily at the behest of the applicant, the Air District agrees that a comprehensive BACT analysis would have to include all sources of greenhouse gas emissions at the facility. The Air District is therefore including the emergency diesel firepump engine and the circuit breakers in its BACT analysis, and is imposing BACT permit conditions for them, in response to these comments.[95] The Air District's response is described below.

[94] *See generally* efficiency degradation data cited in footnotes 85, 89 & 90, *supra*.

[95] The comments also suggested that the Air District should include any natural gas pre-heaters in the BACT analysis. This power plant project does not involve a pre-heater, however, so the Air District disagrees with this element of the comments.

1. Diesel Fire Pump

The emergency diesel firepump engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel, just as with the gas turbines and heat recovery boilers. There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis for the gas turbines. The Air District therefore concludes that the only achievable technological approach to reducing greenhouse gases from the firepump engine is to use the most efficient engine that meets the stringent National Fire Protection Association ("NFPA") standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types instrumentation and control and exhaust systems. (*See generally* Statement of Basis at pp. 55-56, describing the NFPA requirements.) As there is only one control technology to choose from, application of the 5 steps in the Top-Down BACT analysis results in the selection of that control technology.

The 2100 R.P.M. 300-hp Clarke JW6H-UF40 diesel firepump engine that the applicant has proposed for use here has a fuel consumption rate of 14.0 gallons per hour.[96] The Air District has reviewed fuel-efficiency data for similarly-sized NFPA-20 certified firepump diesel engines rated at 2100 R.P.M., and has not found any such engines with a higher fuel efficiency.[97] The Air District has therefore concluded that the 14-gal/hr Clarke engine is the most efficient equipment available, and so it qualifies as the BACT control technology.[98]

The firepump engine may have to be used for up to 50 hours per year for reliability testing and maintenance purposes. Use of the engine at 14 gallons of diesel fuel per hour for up to 50 hours per year would result in total greenhouse gas emissions from the fire pump of 7.6 tons CO_2E per year.[99] The Air District is therefore imposing a greenhouse gas limit in the permit of 7.6 tons per year of CO_2E as a BACT limit. The facility will be required to demonstrate compliance with this limit by recording fuel usage and using an emissions factor of 21.7 lb/ CO_2E-gal to determine resulting CO_2E emissions.

As with turbine emissions, the Air District considered using a CEM to monitor greenhouse gas emissions directly. But it concluded that determining emissions based on fuel usage as a surrogate is a preferable approach, for similar reasons as with the turbines. Fuel usage can be accurately measured, and the amount of greenhouse gas equivalents can be calculated precisely based on well-established emissions factors.

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[96] *See* Clarke JW6H-UF40 Fire Pump Driver, Emission Data for California ATCM Tier 2, Clarke Fire Protection Products (Rev. E, July 12, 2007), at p.1.

[97] *Cf.* Cummins CFP11E-F10 Fire Pump Driver, California ATCM Tier 2 Emission Data (Aug. 26, 2008) (fuel consumption rate of 16.0 gal/hr); Deutz DFP6 1013 C25 fire protection engine, EPA Tier 2/CARB Technical Data Sheet (Apr. 2008) (fuel consumption rate 15 gal/hr).

[98] In the terminology of the "Top-Down" BACT analysis, the Clarke engine at 14.0 gal/hr would be ranked the No. 1 technically feasible control alternative at Step 3 of the analysis. Since the Air District is selecting the top technology, the additional steps in the analysis become moot.

[99] Unlike emissions of criteria pollutants, it is feasible here to impose a numerical emissions limitation for CO_2E because CO_2E has a direct correlation to fuel usage, which is readily measureable. The emissions factor for diesel fuel is 21.7 pounds of CO_2E per gallon.

The Air District published this greenhouse gas BACT analysis and determination for public review and comment in the Additional Statement of Basis. During the second comment period, the Air District received comments suggesting that it consider whether the diesel firepump could be replaced with an electric firepump in order to reduce greenhouse gas emissions. In response, the Air District observes that the facility's fire protection system will actually include an electric fire pump, which is not a direct source of emissions and therefore not covered by the PSD permit.[100] But the facility also requires a diesel engine as a backup alternative in case the electric pump is not operation, as required by NFPA Standard No. 850 (NFPA-850 Electrical Plant Fire Protection). The NFPA standard requires that where multiple fire pumps are required by the fire risk evaluation, "the pumps should not be subject to a common failure, electrical or mechanical, and should be of sufficient capacity to meet the fire flow requirements determined by 6.2.1 with the largest pump out of service." (NFPA-850, § 6.2.5.1.) To meet this requirement, a power plant typically employs two independent means of powering two full-size pumps. The plant's electrical system powers the primary pump, while a diesel engine is frequently used to drive the second pump. In circumstances where there are two independent sources of electrical power available, two electrical pumps have been used to fulfill this requirement, and no diesel fire pump engine has been required. The proposed facility does not have a separate independent means of power available to meet the secondary power requirements for its fire protection system. Use of an electric fire pump engine to meet both the primary and secondary fire pump requirements is therefore not feasible for the proposed facility. The Air District therefore disagrees with the comment that it should require an electric firepump instead of a diesel engine as BACT. Requiring an electric firepump would impermissibly redefine the source because it would change one of the inherent design elements of the facility's fire safety systems – the ability to use a redundant power source so fire suppression is not solely reliant on electric power. This reason for using a diesel firepump engine instead of an electric motor is directly related to one of the central fundamental purposes of this source, to provide redundant fire suppression capabilities. For these reasons, the Air District disagrees that the choice of firepump motive power should be covered by the BACT analysis. Moreover, even if the Air District were required to analyze the use of an electric firepump under the BACT analysis, it would eliminate it at Step 2 in the top-down BACT analysis as not feasible here given the redundant fire-suppression purpose that this equipment will serve.

2. Circuit Breakers

The facility's circuit breakers will also have the potential to emit a greenhouse gas, sulfur hexafluoride (SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks).[101] The facility will include a switchyard with five circuit breakers, and the applicant has proposed breakers containing approximately 145 pounds of SF_6 each in an

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[100] Email from Alex Prusi, PE (Director of Engineering, Calpine) to Dan Ewan (Project Director, Calpine), October 2, 2009.

[101] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006, available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

enclosed-pressure system.[102] SF_6, a gaseous dielectric used in the breakers, is a highly potent greenhouse gas, with a "global warming potential" over a 100-year period 23,000 times greater than carbon dioxide (CO_2).[103] Leakage is expected to be minimal, and is expected to occur only as a result of circuit interruption and at extremely low temperatures not anticipated in the Bay Area. Nevertheless, given SF_6's high global warming potential, even small amounts of leakage can be significant and should be considered for purposes of a greenhouse gas BACT analysis.

STEP 1: Identify Control Technologies for SF_6

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One alternative the Air District has considered is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. One alternative to SF_6 would be use of a dielectric oil or compressed air ("air blast") circuit breaker, which historically were used in high-voltage installations prior to the development of SF_6 breakers. This type of technology is feasible for use here, although SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities.[104]

Another alternative the Air District has considered is to use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year (by weight). In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

The Air District also considered the possibility of other emerging technologies that would replace SF_6 with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.

STEP 2: Eliminate Technically Infeasible Options

The Air District next examined the technical feasibility of each of the control alternatives identified. Looking at oil or air-blast circuit breakers, the Air District concluded that this

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[102] Alstom USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 10, 19.

[103] Letter, David, Mehl (California Air Resources Board, Manager, Energy Section), *Re: Sulfur Hexafluoride (SF6) Emissions Survey for the Electricity Sector and Particle Accelerator Operators*, January 13, 2009, available at: www.arb.ca.gov/cc/sf6elec/survey/surveycoverletter.pdf.

[104] *See* Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, November 1997 (hereinafter, "NIST Technical Note 1425"), available at: www.epa.gov/electricpower-sf6/documents/new_report_final.pdf.

alternative is not technically feasible for this project because it would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers.[105] The proposed project site does not have adequate space within the switchyard to accommodate oil or air-blast breakers. As previously noted, the project has been proposed for location in a densely populated area because, according to the Energy Commission, the project's objectives were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices", and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[106] As a consequence, replacement of the proposed circuit breakers with breakers that do not use SF_6 is not a feasible option for this Project, given the space constraints imposed by construction of the Project on a former industrial site near a source of recycled waste water.

As for the feasibility of enclosed-pressure SF_6 circuit breakers with leak detection, which are far smaller than oil/air-blast breakers for the same application, they are feasible for this location.

Finally, the Air District also evaluated the technical feasibility of emerging alternatives to SF_6. According to the most recent report released by the EPA SF_6 Partnership, "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[107] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications.[108] While some progress has reportedly been made using mixtures of SF_6 and other inert gases (*e.g.*, nitrogen or helium) in lower-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute"[109] for high-voltage applications. The Air District therefore eliminated this alternative as technically infeasible.

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[105] Although the Air District's assessment is that oil and air-blast breakers are not feasible for this project, the District also conducted a BACT comparison between oil/air-blast breakers and SF_6 breakers in Step 4 discussed below. The Air District has concluded that oil/air-blast breakers would be eliminated from the BACT analysis for two separate and independent reasons, because they are technically infeasible under Step 2 and because their ancillary impacts outweigh their net emission benefits under Step 4.

[106] 2002 Energy Commission Decision, *supra* note 17, at p. 17.

[107] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, December 2008, at p. 1 (available at www.epa.gov/electricpower-sf6).

[108] *See, e.g.*, NIST Technical Note 1425, *supra* note 104; *see also* U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF_6", at 185; available at: www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf

[109] Siemens TechTopics No. 53, *Use of SF_6 Gas in Medium Voltage Switchgear*, Siemens Power Transmission & Distribution, Inc. (June 3, 2005), (available at www.energy.siemens.com/cms/us/US_Products/CustomerSupport/TechTopicsApplicationNotes/Documents/TechTopics53Rev0.pdf), at p. 3.

STEP 3: Rank Control Technologies

The Air District then ranked the feasible control technologies. The most effective (and only) control technology that the Air District found to be technically feasible is to use state-of-the-art enclosed-pressure SF_6 circuit breakers. According to information from circuit breaker manufacturers, this equipment can be guaranteed to achieve a leak rate of 0.5% or less.[110] This leak rate meets the current maximum leak rate standard established by the International Electrotechnical Commission ("IEC").[111] This leak rate performance will be further enhanced by an alarm system to alert operators to potential leak problems as soon as they emerge.

Although the District found that oil/air-blast breakers would not be feasible for this particular project, the District nevertheless undertook a comparison between this alternative and the enclosed-pressure SF_6 alternative, which is outlined below. Oil/air-blast breakers would be the top-ranked alternative (with essentially no greenhouse gas emissions) if they had not been eliminated as infeasible. The District has undertaken this additional analysis to compare these two technologies, even though oil/air-blast breakers have already been eliminated, to see whether this alternative would be more attractive if it were feasible here.

STEP 4: Evaluate Most Effective Controls and Economic Impacts and Document Results

Step 4 of the top-down analysis involves consideration of the ancillary energy, environmental and economic impacts associated with using the top-ranked control technologies. Although the Air District eliminated oil/air-blast circuit breakers as not technically feasible at Stage 2 of the Top-Down analysis, the Air District has nevertheless compared that technology to SF_6 breakers to see how it would compare if it were feasible. This comparison shows that the use of the larger oil/air-blast breakers would have significant ancillary environmental impacts that would offset its greenhouse gas benefits, even if it were feasible. Oil/air-blast breakers would require additional land to be devoted to the project, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires. By contrast, according to the National Institute for Standards and Technology, SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads."[112] Accordingly, even if oil/air-blast breakers were not eliminated at Step 2 of the top-down analysis, they would not surpass the choice of SF_6 breakers in Step 4 because of their ancillary environmental impacts.

STEP 5: Select BACT

Based on this top-down analysis, Air District has concluded that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. Breakers using oil or compressed air as a dielectric material are not technically feasible here because of their greatly increased size, and even if they were feasible the offsetting ancillary impacts would not preclude the choice of SF_6.

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[110] Email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.
[111] IEC Standard 62271-1, 2004.
[112] *NIST Technical Note 1425*, *supra* note 104, at p. 3.

Select Appropriate BACT Emissions Limit

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection should be able to maintain fugitive SF_6 emissions below 0.5% (by weight).[113] The Russell City Energy Center will require 5 breakers using 145 lbs of SF_6 each, for a total inventory of 725 lbs SF_6. At a leak rate of 0.5%, annual SF_6 emissions would be a maximum of 3.6 lbs/year, which would equal approximately 39.3 metric tons CO_2E per year. The Air District is therefore incorporating an annual emissions limit of 39.3 metric tons CO_2E per year into the final permit.

Fugitive emissions are, by their nature, very difficult to monitor directly as they are not emitted from a discrete emissions point. Fugitive SF_6 emissions can be estimated very accurately, however, by measuring "top-ups", *i.e.*, the replacement of lost SF_6 with new product.[114] One can conservatively (and very accurately) assume that the amount of SF_6 that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full SF_6 level. The Air District is therefore not requiring monitoring of SF_6 fugitive emissions directly, but is instead requiring surrogate monitoring through measuring the amount of SF_6 lost and using a conversion factor to assess annual SF_6 fugitive emissions in terms of CO_2E. The facility will be required to calculate annual fugitive emissions in this manner to ensure compliance with the 39.3 metric ton CO_2E limit. These monitoring and recordkeeping requirements are consistent with the requirements in other regulatory approaches to the SF_6 fugitive emissions issue.[115]

In addition, as mentioned above, the Air District is requiring the use of an alarm system to alert controllers when a circuit breaker loses 10% of its SF_6. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The facility will also be required to investigate any alarms and take any necessary corrective action to address any problems.

E. Other Greenhouse Gas Issues

Comment III.E.1. – Greenhouse Gas Emissions During Turbine Startup and Shutdown:

The Air District also received comments claiming that it should analyze greenhouse gas emissions from startups and shutdowns. These comments cited an EPA paper stating that

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[113] IEC Standard 62271-1, 2004; email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.

[114] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, *supra* note 101, at p. 1.

[115] *See generally* California Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas emissions, 17 Cal. Code Regs. §§ 95100 *et seq*. (hereinafter, "Mandatory Reporting Rule") (available at: www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf). (Note that the Mandatory Reporting Rule contains a *de minimis* exemption that is not being included in the Federal PSD Permit reporting requirements.) The Mandatory Reporting Rule adopts the reporting protocol developed by EPA's SF_6 Partnership methodology, which requires tracking of the change in inventory, purchases/acquisitions and sales/disbursements of SF_6, and the change in total nameplate capacity. It also adopts the EPA SF_6 Partnership's reporting protocol form, which appears at Appendix A-21.

methane emissions are highest during startup and shutdown, and methane is 21 times more reactive than CO_2.

Response: The Air District agrees that if BACT is to be applied for greenhouse gas emissions, appropriate consideration should be given to startup and shutdown emissions. The same control technology analysis applies to startup and shutdown emissions as applies to steady-state emissions, however: use the most efficient power generation technology that is technologically feasible. (*See generally* BACT analysis discussion for combustion turbine greenhouse gas emissions in the Statement of Basis, in the Additional Statement of Basis, and in these Responses to Comments.) The Air District is unaware of any more efficient generating equipment that would reduce greenhouse gas emissions during startups, and the commenter has not pointed to any. The Air District therefore does not find any reason to alter its greenhouse gas BACT analysis based on startup and shutdown emissions. Moreover, the Air District notes that startup and shutdown emissions will be included in the BACT emission limits. These limits therefore satisfy the BACT requirement for greenhouse gas emissions during these periods to the extent BACT is applicable.

Comment III.E.2. – BACT for Other Species of Greenhouse Gases:

The Air District also received comments stating that it should undertake a BACT analysis for other greenhouse gases besides CO_2, including methane, N_2O and SF_6.

Response: The Air District agrees that if the Applicant wants voluntarily to agree to be subject to BACT limits for greenhouse gases for this project, it should be subject for all of the greenhouse gases that would be emitted from combusting natural gas to generate electrical power, which include CO_2, methane and N_2O as the comments noted. The Air District has therefore included all three of these greenhouse gases in its BACT analysis. These pollutants are emitted essentially in fixed proportions from burning natural gas, and the amounts in which they are emitted are essentially a function of the amount of gas burned. The appropriate BACT technology analysis for all of these pollutants is therefore the turbine efficiency analysis described in the Statement of Basis and Additional Statement of Basis, as elaborated on in these Responses to Comments. The most efficient combined-cycle natural-gas combustion turbine technology for this type of application – *i.e.*, the one that generates the needed power using the least amount of natural gas – is the appropriate BACT technology. Moreover, the numerical BACT limits established in the permit ensure that this level of efficiency will be maintained (with an appropriate margin of compliance); and also provide specific numerical limits for each of these three greenhouse gases (as well as CO_2e, which is a weighted average of the three). With regard to SF_6, the Air District again agrees that if the Applicant wants voluntarily to agree to be subject to BACT limits for greenhouse gases, it must subject any SF_6 emissions to a BACT analysis. The Air District therefore undertook a BACT analysis and established BACT emissions limits for the facility's circuit breakers, which are a potential source of SF_6 emissions.

Comment III.E.3. – Air District Greenhouse Gas Emissions Fees:

The Air District received comments claiming that the permit should acknowledge the greenhouse gas fees that the facility will be required to submit to the Air District under District Regulation 3-334. Some comments questioned whether the facility would be required to pay the same amount of fees if it were to emit fewer emissions.

Response: These comments are correct that greenhouse gas emissions sources such as the proposed Russell City Energy Center will be subject to a permit fee that the Air District charges under its state-law authority to help defray the costs of its climate protection work. This fee is not connected to the Federal PSD Permit, it is imposed in connection with the District's state-law permit. The fee schedule is progressive and linked to the amount of greenhouse gases the facility emits, so that larger projects with more emissions must submit greater fees than smaller projects with fewer emissions. These fees are charged in connection with permit issuance, and are not established as permit conditions. There is no benefit from putting the fee requirement in the permit conditions, as the fees are enforceable and recoverable at the time of permit issuance. Moreover, these fees are not part of the federal PSD permit program, and so they would not belong in a Federal PSD permit in any event.

Comment III.E.4. – Basing Greenhouse Gas Emissions on Natural Gas Consumption:

The Air District received comments stating that greenhouse gas emissions should be evaluated based on natural gas consumption and with ammonia slip included.

Response: The Air District agrees that greenhouse gas emissions should be evaluated (at least in part) based on natural gas consumption, as greenhouse gas emissions are directly related to the amount of natural gas burned. The greenhouse gas mass emissions limits the District is imposing are based on heat input, which is a measure of natural gas consumption. The Air District disagrees, however, that ammonia slip should be considered as having greenhouse gas implications. The Air District is not aware of any evidence that ammonia slip has any significant impact on global climate change, and the commenters have not pointed to any. The Air District published this position in the Additional Statement of Basis (*see* p. 41) and invited any members of the public to comment if they had any information on which to conclude that ammonia should be included as a greenhouse gas in these analyses. The Air District received no further comment on this point, and therefore concludes that ammonia need not be considered in the greenhouse gas analysis.

IV. NO_2 ISSUES

The District also received several comments on its BACT analysis for NO_2. These comments are addressed in this section.

A. Evaluation of "EMx" As An Alternative Control Technology

The Air District received several comments regarding its evaluation of alternative control technologies for reducing NO_2 emissions. The comments the District's analysis of the potential ancillary impacts of selecting Selective Catalytic Reduction ("SCR") as the BACT control technology over EMx technology.[116] With respect to ancillary environmental impacts in particular, the Air District received comments focusing on two areas involving ammonia: (i) the potential for impacts from accidental ammonia releases in connection with the transportation, handling, and storage of the aqueous ammonia that will be used to supply ammonia for injection into the SCR system; and (ii) the potential for impacts from emissions of un-reacted ammonia from the SCR system exhaust ("ammonia slip"). These issues are implicated in the BACT analysis comparison between EMx and SCR because the Air District found in the Statement of Basis (*see* pp. 26-27) that EMx does not use ammonia injection as part of the control system, whereas with SCR the use of ammonia is required as a reagent to reduce the NO_2 to elemental nitrogen and water. As explained below, the Air District disagrees that there are any significant ancillary environmental impacts associated with ammonia injection that would rule out the choice of SCR as the BACT control technology.

<u>Comment IV.A.1. – Currentness of Information Used In Comparing Energy and Economic Impacts of SCR vs. EMx Control Technologies:</u>

The Air District received several comments expressing a concern that the some of the sources of information it used to compare the energy and economic impacts of SCR and EMx control technologies are now several years old. For example, comments questioned whether there may be some better method of estimating the costs of using an SCR control system than using the ONSITE SYCOM Energy Corp. cost analysis adjusted for inflation using the consumer price index. Some comments also questioned whether it was appropriate for the District to rely on a study from 2000 in comparing the energy impacts of SCR and EMx control options.[117]

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[116] The Air District identified both combustion control technologies and post-combustion control technologies as available and appropriate for NO2 emissions control, and required both types of technologies as BACT. (*See* Statement of Basis at 22-29.) The Air District did not receive any comments objecting its choice of combustion controls, and so it is addressing only the post-combustion control elements of the analysis in these responses.

[117] Some comments also expressed a concern about the portions of these documents that were attached as Appendix F in the June 2007 Final Determination of Compliance ("FDOC"), stating that they were excerpts from the full documents, that they were provided without adequate explanation, and that some of the text was not clearly legible. The Air District disagrees that it was inappropriate to append only excerpts of the documents with the FDOC. The Air District appended the relevant portions to assist members of the public in understanding the District's analysis, and appending the full document would simply have added many additional irrelevant pages to the FDOC without any additional benefit. The Air District also disagrees that the

Response: The Air District disagrees that the energy and cost information it used to compare SCR and EMx as control technologies for NO_2 emissions is unreliable as a result of its age. With respect to the relative costs of the two technologies, some of the underlying information the Air District used in its analysis was several years old (although other sources were current), but the Air District adjusted those costs for inflation over that time period to obtain cost estimate information in current dollars. (*See* Statement of Basis at pp. 25-26 and fn. 19.) Adjusting costs for inflation in this way is a well-accepted method of estimating current costs, and the commenters have not suggested that doing so is unreliable in any way, have not suggested that the Air District's estimates are inaccurate, and have not provided any other cost estimate that they contend should be used instead. For all of these reasons, the Air District does not find any reason to question the validity of the cost comparison set forth in the Statement of Basis.

With respect to the analysis of ancillary energy impacts, these technology alternatives have not changed in any significant way since the various sources of information cited in the Statement of Basis were published, and so there is no reason to doubt the current validity of the information for purposes of the BACT comparison. Moreover, none of the comments cited any way in which these relative impacts have changed. The Air District therefore does not find any reason to question the continued validity of the information it used in its energy impact comparison.

Finally, the Air District notes that although the comments questioned the vintage of some of the sources of information that the Air District used in comparing these two technologies, no comment has pointed to any more recent information that could suggest that the Air District's ultimate conclusion – that neither of the two alternative technologies has any ancillary impacts significant enough to warrant elimination from consideration as a BACT technology – was incorrect (with the exception of ammonia-related concerns, which are addressed separately below). Moreover, no commenter has questioned the Air District's ultimate choice of SCR as the appropriate BACT technology. The Air District therefore finds nothing in these comments to

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documents were not adequately explained, as the data was referenced – and its relevance to the BACT analysis explained – in the discussion of the NOx BACT analysis in Section IV.A.1. of the FDOC (p. 108 under the numbering in the version attached with the December 2008 Statement of Basis). The Air District also disagrees that the documentation it appended was not legible. The Air District has reviewed the record copy of the appended information and found it to be legible. The Air District also reviewed the electronic copy it made available on its website, and the appended documents appear legible. (*See* www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2009/15487/B3161_nsr_15487_sb-corrected_121208.ashx.) For all of these reasons, the Air District disagrees that there was anything inappropriate about the data supporting its BACT analysis that it appended to the FDOC. Moreover, the comments did not suggest that there was any additional information that was not included or not clear in what the District appended that would alter the BACT analysis in any way, and the comments have not suggested that the District should have reached a different conclusion or imposed different permit conditions based on the documentation at issue here. The Air District therefore finds nothing in these comments to suggest that it should not issue the permit, or that it should issue the permit with any different conditions.

suggest that it should change its BACT technology analysis for NO_2 controls based on relative economic and energy impacts.[118]

The Air District published this further justification for the basis of its NO_2 BACT alternatives analysis as outlined above in the Additional Statement of Basis in response to these comments, and invited any members of the public who still questioned the accuracy of the information or the outcome of the BACT analysis to comment on how the Air District's information may be inaccurate and what the Air District could do to improve its accuracy. The Air District received no further comment on these issues during the second comment period, and no comment suggesting that the District's NO_2 BACT analysis should have reached a different outcome or that the proposed NO_2 permit limits should be changed (with the exception of ammonia-related issues, which are addressed below). The Air District therefore concludes that the information about the various NO_2 control technologies evaluated is sufficiently accurate and reliable to support the BACT analysis. There is nothing in these comments that would provide any reason why the District's NO_2 BACT analysis or limits are improper or need to be revised based on these issues.

Comment IV.A.2. – Potential For Accidental Ammonia Spills/Releases:

The Air District received several comments expressing a concern about the potential ancillary environmental impacts associated with the risk of an accident or spill that could cause an ammonia release. The Air District addressed this potential impact in the Statement of Basis, and found that it would not be a significant risk for a number of reasons, including the myriad safeguards and regulatory requirements that will be implemented to mitigate the risk of accidental ammonia releases, as well as the fact that the Energy Commission evaluated the risk as part of its CEQA-equivalent environmental review and found that the risk would be less than significant. (*See* Statement of Basis at p. 26.) The Air District therefore concluded that the risks from ammonia use are not significant enough to rule out SCR as a BACT control technology in favor of EMx. Several of the comments criticized the Air District's analysis in this regard. Some comments criticized the Air District's references to the CEC's analysis on ammonia risks. These comments claimed that the CEC found that the there will be a significant risk of health impacts from an accidental ammonia spill, contrary to the Air District's assertion in the Statement of Basis. Other comments questioned whether the applicant has completed the risk-

[118] The Air District also received a comment questioning why, according to the Statement of Basis, it is "not known" whether Kawasaki Heavy Industries plans to make XONON technology available for other manufacturers' turbines, and whether the District should research this information further. The Air District has not researched whether XONON-brand catalytic combustors will be made available for other manufacturers' turbines because this type of combustion technology is available only for small turbine applications, and is not available for large-scale combustors used in large facilities such as this one. (*See* Statement of Basis at p. 24.) The Air District therefore concluded that this technology is not available as a BACT technology choice, making the issue of what manufacturers can provide the technology moot. The Air District published this response in the Additional Statement of Basis and invited members of the public contended that this is an issue that is relevant to the PSD Permit analysis to explain how and why. The Air District did not receive any comments suggesting that this is a relevant issue, and so it continues to believe that the issue is moot.

reduction requirements that the CEC established in Condition HAZ-2 of its license (regarding preparation of a Risk Management Plan and Hazardous Materials Business Plan); and further questioned whether the District should review those plans in assessing the significance of the risks of a potential accidental ammonia releases. Another set of comments focused specifically on the potential hazards to aircraft in the case of an accidental ammonia release. These comments stated that in the event of a release ammonia vapors could act as irritants to pilots and air passengers flying over the area, and in particular could affect pilots' ability to operate their planes safely.

Response: The Air District has reconsidered its analysis of potential hazards associated with ammonia transportation, storage, and use. Based on this review, the Air District has found no reason to alter its conclusion that with the appropriate risk reduction and mitigation measures in place, the ancillary environmental impacts associated with the risk of ammonia releases will not be significant and do not provide a reason to reject SCR as the BACT technology. The Air District is fully aware that ammonia is a hazardous substance and that a catastrophic release of ammonia in sufficient quantities could have significant impacts, including health hazards to workers at the site, to nearby residents and others in the vicinity of the facility, and to crews and passengers of aircraft that could be exposed to released ammonia at harmful levels, among others. But with the appropriate safeguards in place, such as the Federal Clean Air Act's Section 112(r) Risk Management Plan requirements, the requirements of the California Accidental Release Prevention Program, the Safety Management Plan requirements, and the fact that aqueous ammonia will be used and not the more dangerous anhydrous ammonia, among other safety measures, the *risk* of such an occurrence will be minimal. As a result, the *risk* associated with ammonia transportation, storage and use will not be significant. The Air District clearly explained this analysis in the Statement of Basis and further in the Additional Statement of Basis in order to support the District's conclusion that the risks associated with ammonia use are not significant and do not provide a reason to reject SCR as a control technology.[119] The Air District did not receive any comments to the contrary, during either of the comment periods. The only comments the Air District received on these issues addressed the significance of the impact in the unlikely event of a catastrophic ammonia release – not the significance of the *risk* of such a release resulting from the use of ammonia in the SCR system. There Air District therefore finds nothing in any of the comments it has received on this issue to suggest that the risks from ammonia use are sufficiently high to reject SCR as a control technology.[120]

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[119] *See* Statement of Basis at p. 26 & fn. 20, Additional Statement of Basis at 43-44; *see also* CEC Decisions & Staff Assessments cited therein (discussing safety requirements and mitigation measures and reasons why risk less than significant).

[120] Some comments also questioned whether an air quality model that the CEC referenced in its analysis of potential off-site impacts from an accidental ammonia spill – EPA's SCREEN3 model – is appropriate for such an analysis. These comments also questioned whether it was appropriate for the District to rely on the CEC's report, as opposed to validating the modeling results itself. The Air District notes at the outset that it is not aware of any reason why the CEC's analysis, or its conclusion that off-site impacts could be significant if there was an accidental ammonia spill, could be flawed; and the comments have not provided any reason beyond merely questioning the methodology. But in any event, these issues are not relevant to the District's analysis, because the District conservatively assumes that accidental ammonia

Moreover, with respect to the comments regarding the Energy Commission's findings on this issue, the Air District reexamined the Commission's decision and found it entirely consistent with the District's analysis. The Energy Commission expressly found that "[t]he Hazardous Materials Management aspects of the project do not create significant direct or cumulative environmental effects."[121] This finding was based (at least in part) on the conclusions of the CEC staff's Final Staff Assessment, which found that with the appropriate mitigation measures and safeguards against accidental releases, "impacts from the use and storage of hazardous materials [will be] less than significant."[122] Of course, if a major ammonia release was to occur, that situation would entail significant impacts, as the Commission recognized. But like the Air District, the Energy Commission found that the safeguards in place to prevent and/or mitigate any accidental ammonia releases would adequately address this risk, and therefore that the overall impact from the use of ammonia at the facility would not be significant. This finding is consistent with the Air District's assessment in the Statement of Basis – that the potential for harm from accidental ammonia releases is not significant enough to rule out an SCR system using ammonia as a BACT technology. The commenters may have misunderstood the Air District's analysis on this point based on a sentence in the Statement of Basis that could be read to mean that the Air District believes that if an ammonia release occurred it would not have significant impacts. The Air District did not intend to imply such a conclusion, and agrees with the CEC and the commenters that an accidental ammonia release could potentially cause very significant impacts, and that this point is clear and indisputable regardless of any modeling that might be done. The Air District's conclusion in the Statement of Basis was that with the appropriate risk management requirements in place, the risk from the use of ammonia would not be significant enough to rule out SCR with ammonia use as a BACT alternative.

Regarding the comments asking about the Risk Management Plan and Hazardous Materials Business Plan that the facility will be required to prepare in accordance with CEC Condition HAZ-2, those plans are not normally prepared until shortly before construction, and in this case are not required under HAZ-2 until 60 days before construction. The Air District does not have information as to whether the applicant has completed these plans yet, but even if it has not the matter would be irrelevant here as they are not even required yet. What matters is that, under the CEC's conditions of certification and the independent legal requirements that require them even for non-CEC projects, the plans will have to be prepared. Furthermore, the detailed requirements for Risk Management Plans, Hazardous Materials Business Plans, and the other related hazardous materials safeguards are set forth in the appropriate statutes and regulations that govern those plans. The plans are reviewed by the appropriate review bodies (*e.g.*, the hazardous

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releases could well involve significant off-site impacts. There does not appear to be any dispute among the commenters, the CEC, and the Air District on this point. As noted above, the Air District's analysis is based on the conclusion that, with the appropriate safeguards and mitigation measures in place to reduce the likelihood and severity of potential spills, the *risks* associated with potential releases is less than significant.

[121] 2007 Energy Commission Decision, *supra* note 16, p. 115, Finding 3.

[122] California Energy Commission, *Russell City Energy Center, Staff Assessment – Part 1 and Part 2 Combined, Amendment No. 1 (01-AFC-7C)* (June 2007), CEC 700-2007-005-FSA, at pp. 4.4-5.

materials division of the local fire department) before the facility begins operation. Those review bodies are the appropriate expert agencies to ensure that all of the applicable safeguards and precautions are in place. The Air District has no reason to believe that it should (or even could) conduct its own review to ensure that these safety requirements are being met, and the commenters have not cited any reason either. The Air District published this further information in the Additional Statement of Basis, and invited any members of the public who may still contend that final completion of condition HAZ-2 and District review of the Risk Management Plan and Hazardous Materials Business Plan should be a prerequisite to Federal PSD Permit issuance to explain why that should be the case. The Air District did not receive any further comment or information on this point.[123]

Finally, with respect to the comments about the potential hazards to aviation that could be caused if ammonia is released in large amounts and aircrews and passengers are exposed to dangerous levels of ammonia, the Air District agrees that in the event that a catastrophic ammonia release caused such an exposure, that would be a significant impact, as would such exposures to workers, residents, or anyone else who was exposed to high levels of ammonia. But as explained above, the Air District has concluded that with the appropriate safeguards and mitigation measures in place, the risks of such accidental releases will not be significant. The Air District's analysis on this issue with respect to air traffic specifically is the same as described above with respect to the risks potential for harmful ammonia exposures to the general population in connection with the transportation, storage and use of aqueous ammonia.

Comment IV.A.3. – Potential Ancillary Impacts From "Ammonia Slip" Emissions:

The Air District also received a number of comments on the potential for ancillary environmental impacts due to emissions of unreacted ammonia from the Selective Catalytic Reduction ("SCR") System. The SCR system uses ammonia as a reagent in the NOx reduction process, but some ammonia may not be fully used up in the reaction and may be emitted in the SCR exhaust. These ammonia emissions are often referred to as "ammonia slip".

One group of comments claimed that using SCR will have a significant ancillary environmental impact resulting from ammonia slip through the potential for ammonia emissions to contribute to the formation of secondary particulate matter. The Air District evaluated the potential for such an impact in its Statement of Basis documents and found that secondary PM impacts would not be significant – and would not constitute a reason to reject SCR as a control technology – because the Bay Area is nitric-acid limited and additional ammonia emissions will not have sufficient nitric acid to react with to form significant amounts of particulate matter. (*See* Statement of Basis at pp. 26-27 and Additional Statement of Basis at pp. 45, 55-57 (citing a 1997 District memorandum entitled "A first look at NOx/Ammonium nitrate tradeoffs").) The comments the Air District received after publishing these documents criticized the Air District's analysis on this issue. Among other concerns, the comments claimed that the memorandum the District cited in support of its conclusion that the Bay Area is nitric-acid limited was specific only to the San Jose and Livermore areas and cannot be used to support a determination for the

[123] In response to comments about hazardous materials generally, the Air District notes that these hazardous materials measures address the risk from any hazardous materials that might be used or stored at the facility, not just ammonia.

Hayward area. The comments stated that the District should conduct a site-specific study to evaluate the use of SCR in the context of the top-down analysis. The comments also claimed that Air District staff are currently reevaluating the District's earlier conclusion expressed in the cited memorandum that the region is nitric acid limited. Some comments also questioned the District's statement in the support document for the initial permit that the potential impacts of ammonia slip emissions on the formation of secondary particulate matter within the boundaries of the San Joaquin Valley Air Pollution Control District is not known. Other comments also questioned the District's conclusion that secondary particulate impacts are not significant enough to justify elimination of SCR as a control technology for NO_2, and specifically asked what threshold the District would use for considering a secondary particulate impact significant. In general, this first group of comments suggested that the actual secondary $PM_{2.5}$ impacts from the facility may be much larger than anticipated because of the ammonia slip emissions.[124]

Second, the Air District a group of comments noting that ammonia is a hazardous air pollutant in its own right (apart from its potential to act as a precursor in forming PM), and that it could cause health impacts when emitted in the SCR exhaust. Some comments noted in particular that aircraft and air crews and passengers may fly through or near the SCR exhaust plume and in doing so could be exposed to ammonia slip. These comments implied that these potential ancillary impacts has a hazardous air pollutant counsel against selecting SCR as the appropriate BACT control technology for NO_2.

Finally, the Air District also received a third set of comments on this issue from a manufacturer of NOx control technologies that conflicted with the comments in the first two areas. These comments stated that although EMx technology does not use ammonia, it generates ammonia and will therefore cause ammonia slip in a manner similar to SCR technology. The commenter additionally claimed that EMx technology also generates additional greenhouse gases from catalyst regeneration. The commenter cited an emissions ratio of eight pounds of CO_2 emitted through regeneration for every pound of NOx reduced. The commenter stated that the regeneration process also creates ammonia.

Response: The Air District has further considered the potential for ancillary environmental impacts associated with ammonia slip emissions from SCR vs. EMx technology in light of these comments. At the outset, the Air District acknowledges the comments stating that EMx technology will also emit ammonia slip in a manner similar to SCR technology. The Air District is not aware of any independent information that EMx will cause ammonia slip emissions (and the comments did not cite any), although to the extent that this assertion is true it would render this issue moot in the comparison of SCR vs. EMx, as the ammonia slip impacts would be equal. The Air District concludes that it does not have to make a definitive determination of whether EMx technology will or will not cause ammonia emissions, however. Even assuming that SCR

[124] Comments also stated that reducing ammonia slip would reduce the amount of ammonia that the facility would need to transport, store, and use. But to the extent that there would be any incremental benefit from such reductions (which is nothing more than speculative), it would not be significant given that the risks from ammonia transport, storage and use as currently planned are already be less than significant.

involves ammonia slip and EMx does not, the ammonia slip resulting from SCR would not cause significant ancillary environmental impacts sufficient to require SCR to be rejected, as the District explained in the Statement of Basis and Additional Statement of Basis.

In response to comments that ammonia slip could cause secondary particulate matter formation, the Air District reevaluated its initial determination that ammonia slip emissions will not cause any significant secondary $PM_{2.5}$ impacts. This further analysis is explained in full in the discussion of particulate matter issues below, as well as in the section on the PSD source impact analysis for $PM_{2.5}$. (*See* Response to Comment No. VI.2 and Response to Comment No. XIII.B.3., which Responses are incorporated by reference herein.) As explained there, the Air District found that its conclusion that ammonia slip emissions will not be a significant contributor to secondary particulate matter formation is still justified. Based on this detailed analysis and careful consideration of all of these comments, the Air District concludes that its initial assessment in the Statement of Basis is correct. The Air District therefore concludes that ammonia slip emissions would not have a significant collateral environmental impact regarding secondary particulate matter formation that would rule out SCR as a control technology for NO_2 compared with EMx technology.

The Air District has also considered the potential for ancillary environmental impacts from ammonia slip as a hazardous air pollutant in its own right, apart from the potential for contribution to secondary particulate matter. The Air District included ammonia slip emissions in its Health Risk Analysis for the facility, and found that emissions of all hazardous air pollutants, including ammonia and all other such pollutants, would not cause any significant health impacts. Issues concerning this Health Risk Analysis are discussed in more detail in the Statement of Basis at pp. 14-16 and 65-66, the Additional Statement of Basis at pp. 93-95, and in this Response to Comments document below in Section XIV (and with respect to ammonia impacts specifically in Response to Comment XIV.4). In particular, with regard to the comments about the potential for ammonia slip emissions to impact aircrews and passengers in aircraft flying near the project site, the Air District points to the additional health risk analysis it performed for airborne receptors as described in the Additional Statement of Basis at pp. 94-95 and in Response to Comment XIV.7. below.[125] As with the general Health Risk Assessment, this further analysis shows that there will not be any significant ancillary environmental impacts with respect to ammonia or other toxics exposures to aircrews or passengers that would rule out the selection of SCR as the BACT control technology. Based on all of this analysis, the Air District concludes that there will not be any significant ancillary environmental impacts regarding health risks from ammonia slip emissions that would rule out selection of SCR as the BACT control technology.

Finally, the Air District also notes that it examines potential collateral environmental impacts such as these on a case-by-case basis and does not have a bright-line rule for when a potential collateral impact would be considered "significant" or not. But certainly, in a case such as this one where the available evidence suggests that ammonia slip will cause only minimal secondary

[125] Additionally, with respect to aviation safety risks generally, *see* Response to Comment XIX.9. below.

particulate matter formation – if any at all – the potential for such impacts would not be significant enough to eliminate a particular control technology in the BACT analysis.

B. Consideration of Substituting Urea Instead of Aqueous Ammonia As Source of Injected Ammonia For SCR System

Comment IV.B.1. – Use of Urea Instead of Ammonia in SCR System:

The Air District also receive comments stating that, if the Air District does decide to select SCR as the BACT control technology, it should require the facility to use urea instead of ammonia in the SCR system in order to reduce the potential for impacts from accidental ammonia releases. These commenters cited a technology called NOxOUT ULTRA that they claimed was feasible to allow the substitution of urea for ammonia.

Response: The Air District considered the use of urea instead of ammonia in the SCR system in response to these comments. This is a common technology for controlling NOx from reciprocating internal combustion engines, but it is not normally used in combined-cycle power plants. The Air District considered the NOxOUT ULTRA technology cited in the comments, which generates ammonia from urea just before it is injected into the SCR system, thus eliminating the need to store aqueous ammonia at the site.[126] The elimination of ammonia storage would alleviate the risk of any significant amount of stored ammonia being released accidentally, and so the Air District evaluated it as an alternative technology under Step 4 of the Top-Down BACT analysis, in which ancillary environmental impacts are considered to determine whether an alternative technology should be chosen. SCR technology would be equally effective at reducing NO_2 emissions using either ammonia or urea, and so both options would be ranked No. 1 at Step 3 of the BACT analysis. The question at Step 4 is whether one of the alternatives is preferable to the other as a means of achieving the BACT emissions limit, given the potential for any ancillary environmental effects.

The Air District has concluded that because the risks of using SCR with ammonia are so small and will be adequately addressed by the safeguards that the facility will be required to put in place, there will be no additional benefit from using urea instead of ammonia that would be significant enough to reject ammonia use in the BACT analysis and require urea instead. As the Air District discussed in detail above in Response to Comment IV.A.2., the risks of accidental releases of ammonia from the SCR system are slight and will be adequately addressed under applicable industrial safety codes and standards, as addressed by the safety requirements outlined in the Energy Commission's licensing documentation. Given the relatively low risk of accidental releases and the additional safeguards provided by these measures, the District concluded that the potential for impacts from the use of ammonia in the SCR system was not significant enough to reject SCR as a control alternative. For the same reasons, the risk is not significant enough to require the facility to avoid ammonia by using NOxOUT ULTRA instead.

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[126] *See* Product Brochure, "NOxOUT ULTRA NOx Reduction Process", Fuel Tech, Inc., 2001 (attached with Jan. 17, 2009, comment from Doug Kirk, Regional Sales Manager, Fuel Tech, Inc.).

The risk of any significant ammonia problems is sufficiently remote that it does not provide a reason why urea must be chosen under Step 4 in the BACT analysis over ammonia.[127]

Moreover, in addition to the lack of any significant benefit from using urea given the remote and well-controlled nature of the risk from using ammonia, the Air District has also evaluated information suggesting that there may be ancillary adverse environmental impacts from using urea instead of ammonia. One potential ancillary adverse impact the Air District is concerned about is through increased greenhouse gas emissions from urea injection. Studies have shown that urea injection can increase the selectivity of the SCR process in a high-NO_2 environment towards the formation of N_2O, a highly potent greenhouse gas.[128] Any substantial increase in N_2O emissions could have adverse climate change consequences that would outweigh any potential risk reduction benefits from eliminating ammonia storage. Furthermore, according to the NOxOUT-ULTRA product literature, the decomposition of the urea into ammonia for injection into the SCR system requires a burner, which would have to burn fuel and would generate additional greenhouse gases, with similar negative climate change impacts.[129] The Air District would be wary of incurring these ancillary adverse climate change impacts associated with urea use, even if hadn't concluded that the risks associated with ammonia risks are not significant.

Another potentially adverse collateral environmental impact the Air District identified in the Additional Statement of Basis would be through increased emissions of formaldehyde, a hazardous air pollutant and toxic air contaminant. As the Air District explained in the Additional Statement of Basis, data from a similar facility in Sumas, Washington, which had experimented with the use of urea for NOx control for a short period of time, showed that urea injection (as opposed to use of ammonia) resulted in a nearly five-fold increase in formaldehyde emissions.[130]

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[127] The Environmental Appeals Board has also remarked at the remoteness of the possibility of a catastrophic failure of an ammonia SCR system. (*See, e.g.*, *In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 117 (EAB 1997).) The Air District is aware of one incident at a facility in Blythe, CA, in which ammonia was apparently released from a cooling system. That incident apparently involved ammonia used as a refrigerant in a cooling system, not as a reagent in an SCR system, and the amount released was not great enough to cause any injuries. While any industrial incident needs to be taken seriously, the Air District does not believe that this incident establishes that using ammonia in an SCR system poses a significant risk of catastrophic ammonia releases.

[128] *See* Low Temperature Urea Decomposition Phenomena in SCR Systems, C. Scott Sluder (Primary Contact), John M.E. Storey, Samuel A. Lewis, Linda A. Lewis, Oak Ridge National Laboratory, p. 3, available at: www.ornl.gov/~webworks/cppr/y2001/rpt/122007.pdf ("N_2O emissions were examined for both SCR catalysts. The N_2O emissions were found to be higher for both the 152-mm and 76-mm catalysts when urea was injected compared with NH3 injection. The data show that injection of urea causes an increased selectivity of the SCR process in a high-NO2 environment towards formation of N_2O.").

[129] *See* Product Brochure, "NOxOUT ULTRA NOx Reduction Process", Fuel Tech, Inc., 2001 (attached with Jan. 17, 2009, comment from Doug Kirk, Regional Sales Manager, Fuel Tech, Inc.).

[130] *See* Additional Statement of Basis at pp. 44-45; *compare* Valid Results, Inc., test report for June 13, 2002, EPA Method 316 Source Test (0.226 tpy formaldehyde emissions with urea) *with*

The Air District concluded in the Additional Statement of Basis that this potential for increased formaldehyde emissions was another reason not to require the SCR system to use urea instead of ammonia. During the second comment period, the Air District received comments from the developer of NOxOUT ULTRA criticizing this data and the Air District's use of it in its analysis. These comments claimed that the data from the Sumas facility was incomplete, unofficial, not peer-reviewed, and did not amount to a valid scientific finding. The comments also said that the Sumas, Washington unit was an early non-commercial prototype and is not representative of the commercial installations of the product installed since 2003; that the Sumas unit was not functioning correctly at the time of the testing for formaldehyde and, further, that the testing rig had not been properly optimized at that time; and that the study should have considered that the decomposition temperature for formaldehyde is 572°F, while the decomposition temperature in a commercial NOxOUT ULTRA chamber ranges from 1,200°F to 650°F. These comments stated that the NOxOUT ULTA product is designed to decompose urea at low pressure and high temperature to avoid formation of byproducts such as formaldehyde.[131]

The Air District acknowledges the commenter's concerns about relying on only limited data to conclude that urea would involve increased formaldehyde emissions, and agrees that the simple source test comparison it used was not as rigorous as a formal peer-reviewed study. Nevertheless, the limited data the District examined is the only information the District has been able to discover regarding the impact of urea use on formaldehyde emissions. Notably, although the commenter criticized the Air District's reliance on the Sumas data and claimed that there is no credible evidence that urea use will increase formaldehyde emissions, the commenter did not provide any contrary data showing affirmatively that urea use will *not* increase formaldehyde emissions.[132] Given this record, the Air District continues to have concerns about the negative formaldehyde impacts from substituting urea for ammonia in the SCR system, although it finds it

email message from Brian Fretwell to Barbara McBride, Calpine, March 4, 2009 (0.049 tpy formaldehyde emissions without urea).

[131] The Air District also received a letter after the close of the second comment period stating that the formaldehyde emissions come from the coating on solid urea pellets when the urea is used in that form, and that the problem could be avoided by using liquid urea instead of pellets. This letter was not a comment submitted during the comment period, and the Air District is therefore not obligated to respond to it. Nevertheless, the Air District has reviewed the Sumas situation and has found that the tests at Sumas were conducted using liquid urea, not pellets. Moreover, the letter did not provide any documentation or evidence to support its conclusion that increased formaldehyde formation is associated only with urea in pellet form. With no evidence on the pellet issue beyond the Sumas data, which show increased formaldehyde with liquid urea, the Air District has no basis to confirm the assertion in these comments that using liquid urea would avoid the formaldehyde problems observed at Sumas. The Air District therefore disagrees with the letter's assertions that the formaldehyde problems experienced in the Sumas tests could be avoided by using liquid urea instead of pellets. (The letter also referenced cost differences in using pellet vs. liquid urea, but relative costs were not an element of the Air District's analysis on this issue.)

[132] One particular criticism voiced by these comments concerned the conditions under which the tests were conducted. At this date it is impossible to confirm exactly what conditions the testing was performed under, but the Air District is not aware of any specific evidence showing that any of the conditions were unrepresentative or would have led to flawed results.

difficult to conclude with certainty what the potential for such negative impacts may be at this time. Ultimately, however, the issue does not need to be resolved at this time because the Air District has concluded that the risk of accidental releases from ammonia use is not significant enough to require the facility to avoid ammonia by using NOxOUT ULTRA instead of traditional ammonia injection as a BACT requirement. The Air District continues to have concerns about formaldehyde impacts, in addition to these other conclusions, but has determined that it does not need to take a definitive position on these concerns at this time given that the rest of the evidence in the record does not support requiring the use of NOxOUT ULTRA regardless. The Air District would look forward in the future to working with the vendor of this system, and any future project applicants who may wish to explore this technology, to address these issues further.

For all of these reasons, the Air District disagrees with the comments suggesting that it should require the use of urea instead of ammonia for the SCR system under its BACT analysis in order to lessen the risk of ammonia releases.[133] Given the minimal nature of the risk associated with ammonia use, and the potential that there may be countervailing ancillary environmental impacts associated with urea use, the Air District does not believe that using urea to generate ammonia for the SCR system is a superior technology to using aqueous ammonia.

C. NO_2 BACT Emissions Limits

Comment IV.C.1. – Hourly NO_2 Limit:
The Air District received comments stating that the RACT/BACT/LAER Clearinghouse shows one facility with a permit limit of less than 2 ppm NOx – the IDC Bellingham facility, which the comments stated was permitted at 1.5 ppm NOx. The comments suggested that the Air District needs to evaluate the permit for this facility to determine whether a lower limit would be appropriate here.

Response: The Air District addressed this facility in the Statement of Basis. (*See* Statement of Basis at pp. 28-29 and fn. 23.) As the Air District explained there, the IDC Bellingham permit was based on NO_2 emissions of up to 2.0 ppm as a maximum not-to-exceed limit. The permit required emissions during most operating periods to be kept below 1.5 ppm, but it was designed specifically to accommodate the fact that emissions may rise to 2.0 ppm at times. The permit therefore supports the Air District's conclusion that the BACT limit needs to accommodate the fact that emissions can be up to 2.0 ppm. Moreover, as the Air District noted in the Statement of

[133] The Air District notes that the differences between NOxOUT ULTRA and traditional ammonia injection systems concern only ammonia transportation, storage and use, not ammonia slip emissions. Both traditional SCR systems and NOxOUT ULTRA use ammonia in the NOx control reaction. The only difference with NOxOUT ULTRA is that it generates the ammonia from urea just prior to ammonia injection, so the facility does not have to store significant amounts of ammonia on-site. (*See* Product Brochure, "NOxOUT ULTRA NOx Reduction Process", Fuel Tech, Inc., 2001 (attached with Jan. 17, 2009, comment from Doug Kirk, Regional Sales Manager, Fuel Tech, Inc.).) Ammonia slip emissions – as opposed to ammonia storage – is not implicated in the comparison between these two technologies because both will generate ammonia slip emissions.

Basis, that facility was never built and so there are no operating data to determine whether and to what extent emissions could actually be kept below 2.0 ppm. The commenters have not provided any analysis beyond simply reciting the permit condition that the Air District already addressed, and so the District finds no reason to revise its earlier conclusions regarding the NO_2 BACT limit.

Comment IV.C.2. – Annual NO_2 Limit:

The Air District received comments noting that the hourly BACT limit for NOx was updated in the 2007 permitting process, and was reduced from 2.5 ppm to 2.0 ppm. These commenters suggested that the annual limit needs to be adjusted accordingly.

Response: The annual limit established in the 2002 permitting process was based on average annual emissions of 2.0. The Air District concluded during that permitting process that although short-term NOx emissions could be as much as 2.5 ppm, on average over the longer term they would be 2.0 ppm. This new lower limit represents a very stringent BACT standard, and the Air District has no evidence to suggest that the facility will be able to maintain average emissions significantly below 2.0 over the long term. The Air District therefore used 2.0 ppm as the average steady-state emissions rate when calculating the annual facility NO_2 permit limit. The Air District published this further explanation and justification for the annual NO_2 limit in the Additional Statement of Basis, and no commenters provided any further information to suggest that the proposed annual limit is inappropriate or should be changed. The Air District is therefore finalizing the annual limit as proposed.

Comment IV.C.3. – Carlsbad Energy Center NO_2 Limit:

The Air District received comments stating that the proposed Carlsbad Energy Center in Carlsbad, CA, will have lower emissions of a number of criteria air pollutants, including NO_2. The comments stated that Carlsbad will emit only 72.8 tons per year of NOx, compared to Russell City's 127 tons.

Response: In response to these comments, the Air District reviewed the Final Determination of Compliance for the Carlsbad facility. The Final Determination of Compliance reveals that the NO_2 emissions limit is 2.0 ppm, the same as the Air District is imposing here. The reason why the Carlsbad facility's annual emissions will be lower is because the facility will be permitted for operation for only 4,100 hours per year, whereas the Russell City Energy Center will be permitted for full-time operation throughout the year.[134] The Air District therefore disagrees that the proposed Carlsbad facility provides any reason to revisit its BACT analysis here.

[134] *See* Final Determination of Compliance, Carlsbad Energy Center Project, San Diego Air Pollution Control District, Applications Number 985745, 985747, and 985748, August 4, 2009, p. 8 Table 1a (2 ppm NOx limit) and p. 10 (4100 hour operation) (available at: www.energy.ca.gov/sitingcases/carlsbad/documents/others/2009-08-04_SDAPCD_FDOC.pdf) (hereinafter, "Carlsbad Energy Center FDOC").

D. NOx as a Precursor To Secondary $PM_{2.5}$ Formation

<u>Issue IV.D.1. – BACT for NOx as a Precursor to Secondary Particulate Matter Formation:</u>
The Air District has also further reviewed the issue of whether NOx emissions need to be subject to BACT review and permit limits as a precursor to secondary particulate matter formation. The Air District did not receive any specific comments on this issue, but it has nonetheless undertaken further consideration of this issue of its own volition. To the extent that a BACT analysis for NOx is required because of (i) the Bay Area's designation as "attainment/unclassifiable" for the $PM_{2.5}$ annual standard; (ii) EPA's inclusion of NOx as presumptively a $PM_{2.5}$ precursor within the definition of "Regulated NSR Pollutant" for purposes of PSD permitting (*see* 73 Fed. Reg. 28321, 28349 (to be codified at 40 C.F.R. § 52.21(b)(50)(i)(c))); and (iii) the facility's NOx emissions above the PSD significance threshold of 40 tons per year (*see id.* (to be codified at 40 C.F.R. § 52.21(b)(23)(i))), the Air District has concluded that its BACT analysis and limits for NO_2 would satisfy any BACT requirements for NOx. NO_2 and NOx are essentially one and the same pollutant (*see* discussion in Statement of Basis at pp. 21-22), and the BACT controls and emissions limits imposed for NO_2 will be effective to impose the most stringent achievable emissions limits for NOx as well.

V. CARBON MONOXIDE ISSUES

The Air District also received several comments on its BACT analysis for Carbon Monoxide. In response to these comments, the Air District has reconsidered its BACT determination and is lowering the BACT limit for CO from 4.0 ppm to 2.0 ppm in the final permit. The Air District's response to the comments received is set forth below.

Comment V.1. – Determination of BACT Limit for Carbon Monoxide:

A number of comments objected to the District's initial proposal to establish the BACT Carbon Monoxide limit at 4 ppm. These comments claimed that the BACT limit should be set at 2 ppm (or even lower). The comments raised a number of related points on this issue.

- *Use of Data From Metcalf Energy Center:* Several comments criticized the District's use of Carbon Monoxide emissions data from the Metcalf Energy Center as a basis for determining that the appropriate BACT limit should be 4.0 ppm. These comments criticized the District for relying on CO data from a single facility in making its BACT determination, pointing out that there are many other facilities with similar configurations that the District could look to. The comments also claimed that the Metcalf data show that after the first year of operation,[135] the facility exceeded 2 ppm on only 0.4% of the operating days, something that could be addressed through a larger oxidation catalyst.
- *BACT Determinations by Other Agencies:* Some comments also pointed out that other permitting agencies have adopted BACT limits for CO at levels below the 4.0 ppm the District proposed. Comments cited a June 18, 2001, EPA letter to the San Luis Obispo County APCD stating that BACT for CO should be 2.0 ppm (3-hour average). Comments also cited several projects permitting with a 2 ppm CO limit in conjunction with a 2 ppm NOx limit. Comments also cited several facilities identified in EPA's RACT/BACT/LAER Clearinghouse with even lower CO limits, including Kleen Energy Systems at (0.9 ppm), CVP Warren, VA (1.3 and 1.8 ppm).
- *Distinguishing Permits With Lower CO Limits But Higher NOx Limits:* Some comments also criticized the District for distinguishing facilities that are achieving lower CO limits, but have higher NOx limits, on the grounds that there is a tradeoff between reducing NOx and reducing CO. These comments claimed that prioritizing NOx and VOC reductions over CO reductions is inconsistent with BACT, stating that BACT requires that the emissions limit for each pollutant must be the lowest achievable. Comments also stated that the NOx/CO tradeoff occurs only in the combustion equipment, and that even so more efficient combustion equipment would achieve similar reductions in both pollutants. The comments also claimed that the post-construction controls reduce NOx and CO independently and bigger control equipment can reduce both pollutants simultaneously. Some comments generally acknowledged the NOx/CO tradeoff, but stated that the District did not cite any justification in the record for its assertion that a low NOx limit requires a higher CO limit. These comments stated that even if a CO limit above 2.0 ppm CO would be necessary to allow the facility to achieve a 2.0 ppm NOx

[135] These comments also stated that Metcalf was originally permitted without an oxidation catalyst, which they claimed is a further reason to ignore the first year of emissions data.

limit, the District did not provide an explanation in the record for how high above 2.0 ppm the limit would have to be, and why a limit of 4.0 ppm is justified. A number of the comments cited several other facilities that have been permitted with low NOx and low CO limits to support their claims.

- *Distinguishing Permits With Lower CO Limits But Longer Averaging Times:* Some comments also claimed that the District should not have rejected facilities with lower CO limits as comparable on the grounds that the limit included a longer averaging time. The comments questioned the District's assertion that the 3-hour averaging time used for some permit limits at 2.0 ppm makes a limit lower than 4.0 infeasible here. Some comments claimed that averaging time is irrelevant to the emissions performance of the oxidation catalyst, which they claimed can achieve the same level of control on a continuous basis. Other comments claimed that even if using a 1-hour averaging time necessitates a limit over 2.0 ppm, the District has not explained why the limit needs to rise to 4.0 ppm. Finally, comments also claimed that there are several other facilities meeting achieving low NOx and low CO emissions, even with short (1-hour) averaging periods.
- *Distinguishing Permits With Lower CO Limits From Facilities That Have Not Yet Been Built:* Some comments also claimed that the District should not distinguish facilities that have been permitted with lower CO limits but have not yet been built. The comments asserted that another agency's determination that a CO level is achievable by itself is sufficient to conclude that it is feasible, absent a clear demonstration to the contrary. The comments claimed that a number of BACT determinations by other agencies indicate that a lower limit is achievable, and that the District should address the achievability of these lower limits.
- *Accommodating Transient and Low-Load Conditions:* Comments also criticized the District for setting the BACT limit based on what is achievable during transient and low-load conditions. Comments claimed that if transient and low-load conditions require a higher permit limit, the District should impose a 2-tier limit with one limit for normal operations and a higher one for transient/low-load. The comments also questioned the need for a higher limit for transient conditions at all, citing the experience of the Carlsbad Energy Center – which they claimed is a peaker facility and therefore subject to even more transient loads – which was permitted at 2.0 NOx and 2.0 CO (1-hr average).

Response: The Air District has evaluated these comments and has reconsidered its assessment of the available data and related information on what level of CO emissions is achievable. The Air District agrees that the appropriate BACT limit should be more stringent than the 4.0 ppm that the District initially proposed. The Air District has concluded that the appropriate BACT limit should be established at 2.0 ppm instead, as discussed below, and is therefore imposing a CO limit of 2.0 ppm, averaged over 1 hour, in the final permit.

- **Observation Regarding NOx/CO Emission Reduction "Tradeoff"**

Before reaching the question of the appropriate numerical BACT limit, however, the Air District first responds to the comments regarding the tradeoffs between lowering NOx emissions and lowering CO emissions, and between lowering the numerical emissions rate and shortening the averaging time. These tradeoffs are important considerations to take into account when adopting BACT emissions limits. For the NOx/CO tradeoff, the technical realities of controlling these two pollutants means that lowering combustion temperatures to decrease NOx formation necessarily means that CO emissions will be increased because lower temperatures increase incomplete combustion. (*See generally* Statement of Basis at p. 29.) This is an important consideration to take into account in the BACT analysis for Carbon Monoxide, as the analysis is required to consider ancillary environmental impacts. Increasing NOx is an especially important ancillary environmental impact for the Bay Area because NOx is an ozone precursor and the Bay Area is not in compliance with the federal and state Ambient Air Quality Standards for ozone. For the tradeoff between lower permit limits and longer averaging times, the longer the averaging time the more opportunity there is for short-term emissions spikes to be averaged out by lower emissions before and after the spike. With a shorter averaging period, the numerical emission rate normally has to be set higher to accommodate such short-term spikes. A longer averaging time allows the numerical emissions rate to be set lower, which can have the effect of reduced emissions over the long term. The District therefore disagrees, as a general matter, with the commenters who discounted the importance of these tradeoffs in the District's approach to air pollution control. This issue is ultimately immaterial in the question of what BACT limit to impose here, however, as these tradeoffs are not being made part of the District's BACT analysis for this permit. The Air District's CO BACT analysis is based on the lowest achievable CO emissions rate taking into account ancillary environmental, economic and energy impacts, without regard to NOx considerations.

- **Reduction of CO Emissions Limit from 4.0 ppm in Initial Proposal to 2.0 ppm**

Turning to the question of what numerical BACT limit is appropriate for this facility, the Air District has reevaluated its assessment from the Statement of Basis that while CO emissions can be kept below 2 ppm under most conditions, under some conditions (*e.g.* transient load conditions) emissions may rise to as high as 4 ppm. (*See* Statement of Basis at p. 32.) The Air District finds it significant, as pointed out by a commenter, that the operating data from the Metcalf Energy Center, a similar operation, show that only 0.4% of the days of operation showed any exceedance of 2.0 ppm after the first year of operation. The Air District agrees that a more critical analysis of this data suggests that it is possible to design the system to ensure that Carbon Monoxide emissions are maintained below 2.0 ppm at all times.

The Air District also agrees with the commenters that the significant number of permitting agencies that have issued permits with Carbon Monoxide limits below 4.0 casts doubt on whether 4.0 is the lowest emissions performance that is achievable for this type of equipment. The Air District notes that there were a total of 8 permits identified in the Statement of Basis with Carbon Monoxide limits of 2 ppm (either with 1-hour averages or 3-hour averages), suggesting an emerging consensus that this performance level is achievable. (*See* Statement of Basis, Table 11, pp. 32-33.)[136] Based on this further assessment of the data, and on the large

[136] The Air District disagrees with the comments that the mere issuance of a permit with a particular limit establishes that limit as BACT, without some further demonstration that the limit is achievable. A permitting agency may issue permits with very stringent limits with little or no technical justification at all if the applicant does not object to it. In such a situation, where there

number of permitting agencies that have required other similar facilities to limit Carbon Monoxide emissions to 2.0 ppm averaged over 1 hour, the Air District concludes that this 2.0 ppm limit (1-hour average) should be required here as BACT. If this limit is being applied and demonstrably achieved at other facilities, that fact supports a presumption that it is an achievable limitation at this facility for purposes of BACT.

- **Consideration of CO Emissions Limit Below 2.0 ppm**

Finally, the Air District also considered the comments regarding permits that have been issued containing Carbon Monoxide limits below 2.0 ppm, for Kleen Energy Systems[137] and CPV Warren[138], and whether it might be appropriate to impose a BACT CO limit below 2.0 for this facility. The Air District notes that neither of these facilities has been built yet and so there is no operating data available on which to assess whether they will actually be able to meet these lower limits. This point, along with the fact that the consensus among other permitting agencies appears to have coalesced around 2.0 for most facilities, underscores the requirement that lower limits must be considered on a case-by-case basis. The Air District has therefore evaluated whether a CO emissions limit of less than 2.0 ppm would be achievable by this particular facility, "taking into account energy, environmental and economic impacts and other costs" as is required in establishing a BACT limit.

To undertake this analysis, the Air District evaluated information from the applicant on the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining emissions below 1.5 ppm.[139] Based on these analyses, the cost of achieving a 1.5 ppm permit limit would be an additional $179,600 per year (above what it would cost to achieve a 2.0 ppm limit), and the additional reduction in CO emissions would be approximately 11 tons per year, making an incremental cost-effectiveness value of over $16,000 per ton of additional

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is no justification for the limit nor any operating data to show that the limit can be complied with, the mere existence of the permit limit would not, without more, establish that the limit is achievable as a technical matter. This point is moot for the Carbon Monoxide analysis here, however, as the Air District has specifically examined whether a limit below 2.0 ppm should be required as BACT here. Based on this case-specific analysis, the Air District has concluded that BACT would not require a lower limit for this facility. There is nothing in the permitting documents for Kleen Energy Systems, CPV Warren, or any other facility to suggest that lower limits should be required for Russell City.

[137] New Source Review Permit to Construct and Operate a Stationary Source, issued to Kleen Energy Systems, LLC, by Connecticut Department of Environmental Protection, Bureau of Air Management, February 25, 2008.

[138] Prevention of Significant Deterioration Permit, Stationary Source Permit to Construct and Operate, issued to CPV Warren LLC, by Virginia Department of Environmental Quality, State Air Pollution Control Board, July 30, 2004, as amended January 14, 2008.

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

CO reduction.[140] Moreover, the total cost of achieving a 1.5 ppm CO limit (as opposed to the incremental costs of going from 2.0 ppm to 1.5 ppm) would be over $840,000 per year, and the total emission reductions of a 1.5 ppm limit would be 186 tons per year, resulting in a total (or "average") cost effectiveness value of over $4,500.[141] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.5 ppm CO permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 1.5 ppm limit would be far more expensive, on a per-ton basis, than what other similar facilities are required to achieve. The Air District has not adopted its own cost-effectiveness guidelines for CO,[142] but a review of other districts in California found none that consider additional CO controls appropriate as BACT where the total (average) cost-effectiveness will be greater than $400 per ton, or where the incremental cost-effectiveness will be over $1,150 per ton.[143] Moreover, a review of recent CO BACT determinations in EPA's RACT/BACT/LAER Clearinghouse did not reveal any permits that had imposed CO controls at a cost-per-ton in the range that would be required here. The permits in the Clearinghouse going back through 2005 that included cost-effectiveness information showed a limit of 1.8 ppm being imposed based upon an average cost-effectiveness of $1,750 per ton of CO;[144] a limit of 3.5 ppm based upon an average cost-effectiveness of $2,736 per ton and an incremental cost-effectiveness of $5,472 per ton;[145] and a limit of 2.0 ppm an average cost-effectiveness of $1,161 per ton of CO.[146] Both the average and incremental cost-effectiveness values of imposing a 1.5 ppm limit for the Russell City facility would be substantially higher than what was required for any of these other similar facilities.

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

[141] *See* Spreadsheet, Average/Total Cost Effectiveness Analysis for CO Control from 2 to 1.5 ppmv, prepared by Barbara McBride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.

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

[143] *Cf.* South Coast Air Quality Management District, *Best Available Control Technology Guidelines*, August 17, 2000, revised July 14, 2006 (hereinafter, "South Coast BACT Guidelines"), at 29 (available at: www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf); Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008 (available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf.)

[144] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power, Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008.

[145] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005.

[146] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005.

Because both the average and incremental costs per ton of CO that would be reduced by imposition of a CO limit below 2.0 ppm are significantly higher than the costs that have been or would be required at other similar facilities, the Air District is not requiring that level of control as BACT. Although it appears that an additional reduction below 2.0 ppm may well be feasible based on permits that have been issued to other facilities, the Air District would eliminate it as a BACT requirement in Step 4 of the Top-Down BACT analysis because it is not "achievable" for purposes of a BACT analysis taking into account cost/economic impacts.

The Air District published the revised analyses outlined above in the Additional Statement of Basis, and received several additional comments during the second comment period. One set of comments asserted that the District had not adequately explained why a CO limit of less than 2.0 should not be required as BACT based on the Kleen Energy permit and CPV Warren permits. These comments cited passages from the NSR Workshop Manual about how a BACT determination must be justified, and stated that the District has not adequately explained why it is not proposing a CO limit of less than 2.0 based on those permits. These comments also stated that the mere fact that those facilities have not yet been built and thus have no operating data to show whether the lower limits are achievable is not a sufficient basis on which to conclude that the limits are not in fact achievable. These comments also objected to the Air District's observation that there appears to be a consensus forming among PSD permitting agencies that 2.0 is an appropriate BACT limits for sources such as this one.

In response to these comments, the Air District disagrees that the Kleen Energy and CPV Warren permits require that the BACT limit must be less than 2.0 ppm for this facility. The Air District agrees with the assertion that a BACT determination must be justified based on technical analysis and evidence, but points out that it has fully justified its determination that 2.0 ppm is in fact the appropriate BACT limit for this facility, as discussed above and in the Additional Statement of Basis at pp. 47-49. The Air District also agrees that the mere fact that a facility has not been built is not enough evidence on which to conclude that the permit limits for the facility are not appropriate elsewhere, but the fact that Kleen Energy and CPV Warren have not yet been built was not the basis for the Air District's determination. To the contrary, the Air District cited the fact that those facilities have not been built simply to point out that there is not operating data available for them and so the Air District needs to look to other sources of information regarding whether a limit below 2.0 ppm would be appropriate in this particular case. (*See* Additional Statement of Basis at pp. 47-48.) The Air District did undertake such an analysis in this case, and found that a lower limit below 2.0 ppm should not be required as BACT because of the relatively low cost-effectiveness of a lower limit compared to controls that are required as BACT at other similar facilities. It was this cost-effectiveness analysis that led the Air District to conclude that a limit below 2.0 was not warranted here, not the fact that the Kleen Energy and CPV Warren facilities have not bee built. Finally, the Air District continues to believe that there is a developing consensus among permitting agencies that in most instances 2.0 ppm is the appropriate BACT limit for CO, based on the large majority of recent permitting decisions using a 2.0 ppm BACT limit.[147] The Air District's BACT determination was made based on a specific

[147] Notably, EPA Region 9 – the EPA Region on whose behalf the Air District issues PSD permits – recently concluded that 2.0 ppm constitutes BACT for a similar facility in King's

evaluation of the appropriate limit for this facility, however, and a determination that a lower limit below 2.0 ppm would not be sufficiently cost-effective compared with the kinds of control requirements are imposed at other facilities.

Another set of comments the Air District received during the second comment period concerned the cost-effectiveness comparisons the Air District made with other similar facilities. Some of the comments criticized the District's comparison of the cost of imposing a limit below 2.0 ppm with the South Coast and San Joaquin Valley air districts' CO cost-effectiveness thresholds. The comments stated that the South Coast's threshold is established for minor source BACT determinations and is not relevant for permitting major source PSD permits. The comments also stated that the San Joaquin Valley air district is not an approved PSD permitting authority and that its cost-effectiveness threshold would not be allowed if the agency were to do PSD permitting.

Other comments on this issue criticized the District's comparison with CO BACT determinations made by other permitting agencies. These comments stated that the determinations that the District cited were situations where the agencies found that CO controls would be cost-effective, and so they are examples of costs that would be justified but do not set a ceiling on how high costs would have to be before they are not justified. The comments also cited a 2000 BACT determination for the Sithe Heritage facility in Scriba, NY, finding that $3,412 per ton was justifiable but stating that costs of over $6,000 per ton would not be justifiable; and a 2002 survey from the Air and Waste Management Association ("AWMA") finding that average cost-effectiveness of CO controls required in Arkansas was $3,373 per ton and in Michigan was $4,944 per ton. The comments also noted that for other pollutants, cost-effectiveness thresholds in the range of $5,000 to $10,000 have been established (although they noted that cost-effectiveness considerations are pollutant-specific, so other pollutants do not necessarily provide a precedent). The comments stated that the District should analyze further whether a CO limit below 2.0 ppm should be required as BACT using a different threshold for considering cost-effectiveness.[148]

The Air District disagrees with these comments that the cost-effectiveness of the more stringent CO limit in this case – $16,000 per ton of additional CO prevented compared with a 2.0 ppm limit, and $4,500 per ton of CO prevented in total – warrants imposing a BACT limit below 2.0 ppm. With respect to the San Joaquin Valley air district's threshold, the Air District disagrees that it makes any material difference that the San Joaquin Valley district does not have delegated

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County, CA. *See* EPA Region 9, Avenal Energy Project (SJ 08-01), Prevention of Significant Deterioration Permit, Proposed Permit Conditions, EPA Docket ID No. EPA-R09-OAR-2009-0438-0001, June 2009, p. 6.

[148] The Air District also received a comment stating that it had not made clear what the costs associated with additional CO control would be. The Air District disagrees with this comment, and notes that it has published all of the cost information on which it based its assessment. All of that information was set forth in the spreadsheets on which the cost-effectiveness analysis was based, which were clearly cited in the footnotes supporting the cost-effectiveness summary (*see* Additional Statement of Basis at p. 45 and footnotes cited therein) and were made available for public review during the second comment period.

PSD permitting authority. That agency's BACT requirement is set forth in its non-attainment NSR program and reflects a level of control that is at least as stringent as BACT required for PSD permitting purposes.[149] The Air District therefore continues to consider that agency's threshold as instructive in determining how to analyze cost-effectiveness.[150] As for the South Coast's threshold, the comments correctly note that it applies for non-major facilities, but it is the only cost-effectiveness threshold the agency has. For major facilities the South Coast does not take cost into consideration at all,[151] and so the major facility context would not be an appropriate comparator when trying to establish how to apply a PSD permit analysis that explicitly considers costs in the BACT review. The non-major context is the only appropriate comparison that can be made if one wants to examine how that agency evaluates cost-effectiveness of imposing additional air pollution controls. For these reasons, the Air District disagrees that its comparison with these two other California air districts was flawed. Although the comparisons are not perfect because they do not involve the exact same PSD permitting situation, they are still valid to the extent that they show what level of costs other agencies consider appropriate when balancing costs against additional emissions reductions, as the Air District is required to do here. The Air District also notes that these agencies' thresholds are also in line with the Yolo-Solano Air Quality Management District's threshold of $300/ton for CO, which further supports the use of a threshold in this cost range as an indicator of other agencies' practices in this area.[152]

Regarding the additional cost-effectiveness data points cited in the comments – $3,412/ton from the 2000 Sithe Heritage BACT determination and the $3,373/ton and $4,944/ton numbers cited in the 2002 AWMA survey for Arkansas and Michigan, respectively – the Air District disagrees that these examples require the Air District to impose a lower CO limit here. First, the determinations the District relied on in its comparison were considerably more recent than the examples cited in the comments, being from 2005-2007 instead of 2000-2002. Furthermore, for the AWMA survey, the survey data indicate that BACT determinations can vary significantly from state to state. But the survey does not provide any information on how BACT determinations have been conducted in California, the state where this facility will be located; and with respect to the CO cost-effectiveness analysis, it provides data from only two out of the

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[149] *See* San Joaquin Valley Air District Rule 2201, Section 3.9.

[150] The comments also stated that the San Joaquin Valley's threshold is not a true cost-effectiveness calculation but a "marginal" cost-effectiveness measure that looks only at the incremental costs and benefits involved in reducing emissions from the district's regulatory requirements to a proposed more stringent level of control. But to the extent that this is true, and the San Joaquin Valley thresholds are for incremental cost-effectiveness, that would just make the cost-effectiveness for this project even more outside the range of what San Joaquin Valley would require. The incremental cost-effectiveness of a lower CO limit here is $16,000 per ton, which is over 50 times greater than the San Joaquin Valley threshold.

[151] *See* South Coast BACT Guideline document, *supra* note 143, at p. 17.

[152] *See* Final Staff Report, Update to Rule 2201 Best Available Control Technology ("BACT") Cost-Effectiveness Thresholds, San Joaquin Valley Air Pollution Control District (May 14, 2008), at p. 4 (available at www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf) (surveying cost-effectiveness thresholds for various California air districts).

50 states.[153] The survey is therefore far from a conclusive determination of what cost-effectiveness threshold the Air District should apply here. Moreover, even viewed as conservatively as possible, it merely confirms that an average cost-effectiveness of $4,500 per ton is on the higher end of the range of reported averages from two other states. It does not lead the Air District to conclude that it must require more stringent emissions limits at this level of cost-effectiveness.

Moreover, to get a more comprehensive and recent understanding of what CO cost thresholds are being used in permitting analyses by other agencies, as well as to evaluate analyses where CO control measures have been rejected on cost-effectiveness grounds, the Air District also examined a database of other combustion turbine permitting decisions from around the country maintained by EPA Region 4. This database lists over 800 combustion turbine plants and provides information about how they were permitted and what control technology they use. For many of the plants, the database also provides information about the costs of control technologies that were not selected. The database lists many projects where CO control measures were rejected where they had a cost-effectiveness of less than $2,000 per ton.[154] Based on this review, the Air District disagrees with the comments that a lower CO limit should be required at a total cost-effectiveness of $4,500 per ton based on the small number of examples cited in the comments. A more comprehensive review shows that rejecting CO controls at that cost-effectiveness level is the norm among permitting agencies, not the exception.

Finally, with respect to cost-effectiveness thresholds that have been established for other pollutants, the comments are correct that cost-effectiveness is addressed on a pollutant-specific basis. For other pollutants besides carbon monoxide, a greater amount of cost can be justified, because the Bay Area is attainment of all applicable state and federal air quality standards for carbon monoxide, whereas it exceeds applicable standards for other pollutants. The Air District therefore disagrees that the examples from other pollutants have much bearing on the CO cost-effectiveness question, as the comments appear to recognize.

For all of these reasons, the Air District disagrees with these comments that it should require a CO limit below 2.0 ppm based on the additional costs that would be involved in achieving such a limit.

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[153] Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies, Nishat H. Hydari, Adeel A. Yousef and Dr. Howard M. Ellis, QEP, Paper # 42752, Air and Waste Management Association (AWMA) Meeting June 2002.

[154] *See* EPA Region 4, "National Combustion Turbine List," available at www.epa.gov/region4/air/permits/national_ct_list.xls. Projects rejecting CO control measures at less than $2,000 per ton include Tenaska Alabama IV Partners (rejecting Catalytic Oxidation at $1506/ton CO); Calpine Blue Heron Energy Center (rejecting Catalytic Oxidation at $1553/ton CO); Columbia Energy (rejecting Catalytic Oxidation at $1611/ton CO); Santee Cooper Rainee Generating Station (rejecting Catalytic Oxidation at $1717/ton CO); Reliant Energy Cardinal Woods River Refinery (rejecting Catalytic Oxidation at $1993/ton CO); and Mid America Cordova Energy Center (rejecting Catalytic Oxidation at $1307/ton CO).

<u>Comment V.2. – Collateral Environmental Impacts Comparison Between Different Types of Oxidation Catalysts:</u>

The Air District also received comments claiming that different types of oxidation catalysts will have different impacts on HAP and POC emissions, citing a 2002 EPA memorandum regarding HAP emissions from combustion turbines ("Roy Memorandum").[155] The comments claimed that the SCONOx system reduces VOCs and HAPs while also reducing CO emissions. The comments claimed that the District should evaluate the differences between different types of oxidation catalysts in its CO BACT analysis.

Response: The Air District disagrees that there is evidence that different kinds of oxidation catalysts will have different impacts on HAP and POC emissions. The memorandum the comment relies on does not state that different oxidation catalysts will have different impacts on HAP and POC emissions. To the contrary, the memorandum (including its attachment) identify several specific types of catalysts, such as platinum, palladium, rhodium, and metal oxides, and discusses them all generally simply as "oxidation catalysts". (*See* Roy Memorandum at p. 6.) Moreover, the memorandum does not claim that SCONOx has any different impact on HAP or POC emissions than any other type of oxidation catalyst. To the contrary, it explicitly states that the two technologies are "comparable" in this regard, and in fact bases its evaluation of all oxidation catalysts generally on an evaluation of SCONOx. (*See id.* at p. 1.) The only difference the memorandum points out between the two technologies is that SCONOx uses a chemically modified catalyst so that the catalyst also removes NOx. (*See id.*) For the Russell City Energy Center, the District is approving SCR for NOx control, and so the NOx-removal aspect of SCONOx does not provide any improvement over the combination of SCR for NOx control and an oxidation catalyst for CO control. The Air District is unaware of any studies on different types of oxidation catalysts and associated abatement efficiencies for VOCs and HAPs, and has found nothing in this comment or elsewhere that warrants revising the BACT analysis for CO. The Air District published this further justification and analysis in the Additional Statement of Basis, and did not receive any further public comment on this issue.

<u>Comment V.3. – Carbon Monoxide Limits for Startups:</u>

The Air District also received comments questioning whether the Carbon Monoxide permit limits will be appropriate for days when turbine startups occur.

Response: The District proposed and is finalizing BACT permit limits both for normal operations and for startups. Startup issues are discussed below in response to comments on startups. Short-term emission limits will be specific to startup operations, as startups by their nature involve more carbon monoxide emissions. Daily and annual limits will include all facility emissions, including emissions from startups. The carbon monoxide limits in the permit will be appropriate for days when turbine startups occur.

[155] The memorandum cited is available at www.epa.gov/ttn/atw/combust/turbine/cttech8.pdf.

VI. PARTICULATE MATTER ISSUES

The Air District also received a number of comments on Particulate Matter issues during both public comment periods. The Air District received comments in the first comment period, and then revised its proposed particulate matter limits in the August, 2009, draft permit and Additional Statement of Basis. The Air District then received further comments in the second comment period. The District is finalizing the particulate matter limits it proposed in the August, 2009, draft permit. The District responds to all of the comments it received on particulate matter issues in both comment periods in this section.

Comment VI.1. – Applicability of PSD Permitting Requirements for Fine Particulate Matter ($PM_{2.5}$):

The Air District received a number of comments about the evolving federal regulatory landscape regarding fine particulate matter with a diameter of less than 2.5 microns ("$PM_{2.5}$"), and whether the Air District is required to conduct a PSD review for $PM_{2.5}$. EPA has promulgated National Ambient Air Quality Standards ("NAAQS") for $PM_{2.5}$, setting standards for 24-hour average ambient concentrations and annual average ambient concentrations. Until recently, the San Francisco Bay Area was administratively designated as "attainment/unclassifiable" for these standards, making the region subject to the PSD permit requirements of the Federal Clean Air Act and 40 C.F.R. 52.21 for $PM_{2.5}$. The EPA Administrator signed a document designating the Bay Area as non-attainment of the 24-hour standard on December 18, 2008, but the document was never published in the Federal Register and so the designation did not become legally effective, leaving the Bay Area technically still designated as attainment/unclassifiable. The current EPA administrator then signed a second document designated the Bay Area as non-attainment of the 24-hour standard, which has been published in the Federal Register and became effective December 14, 2009. As a result, the Bay Area is now a non-attainment area for the 24-hour $PM_{2.5}$ standard, making it subject to Non-Attainment NSR permitting and removing it from the realm of PSD permitting for that pollutant. Throughout most of this permit proceeding, however, the Bay Area was still classified as "attainment/unclassifiable".

The Air District has tracked this evolving regulatory landscape during this permitting proceeding. When the Air District issued its initial Statement of Basis, the Bay Area was still designated attainment/unclassifiable for $PM_{2.5}$. At the time, EPA's regulations required the District to address $PM_{2.5}$ issues in PSD permitting by relying on its PM_{10} analysis as a surrogate for ensuring compliance with $PM_{2.5}$ requirements ("surrogate policy"). Based on its PM_{10} analysis, the Air District therefore concluded in the initial Statement of Basis that the facility would satisfy PSD requirements for $PM_{2.5}$ as well. During the first comment period, the Air District received a number of comments criticizing its reliance on this surrogate policy, as well as criticizing the policy itself as being illegal. Comments stated that reliance on the surrogate policy was optional for state agencies. Some comments implied that the surrogate policy should not apply for this facility by implying that the permit application was not submitted before the July 15, 2008, expiration date that EPA established for the policy. Comments stated that the surrogate policy was inappropriate where the Bay Area was not in attainment of the $PM_{2.5}$ NAAQS, and when the non-attainment designation becomes effective the District will be required to address $PM_{2.5}$ pursuant to 40 C.F.R. Part 51, Appendix S. These comments stated that the District should proceed to address $PM_{2.5}$ even before the designation becomes effective, and implied that doing so would require the facility to use LAER and provide offsets for $PM_{2.5}$ and identified precursors. Some comments claimed that the permit should be denied because the Bay Area is not in attainment of the $PM_{2.5}$ standard, and claimed that permitting any new $PM_{2.5}$ source would be inconsistent with the Air District's other regulatory initiatives to reduce $PM_{2.5}$ pollution. Other comments stated that the Air District should explain the $PM_{2.5}$ regulatory context better to help the public understand what is going on.

Response: Subsequent to the initial Statement of Basis and first comment period, EPA issued a stay of the surrogate policy under 40 C.F.R. 52.21(i)(1)(xi) and proposed to repeal it.[156] In response to this change in EPA policy, the Air District declined to use the surrogate policy, as requested by many of the comments. The Air District then went ahead and included $PM_{2.5}$ issues directly in its PSD permitting review. PSD permit analysis requires the Air District (i) to demonstrate that the facility will use Best Available Control Technology to control $PM_{2.5}$ emissions; and (ii) to conduct an Air Quality Impact Analysis showing that the facility will not contribute to an exceedance of the $PM_{2.5}$ NAAQS (either the 24-hour standard or the annual standard). The Air District conducted these analyses and published them in the August 2008 Additional Statement of Basis. The August 2008 Draft PSD Permit included proposed BACT conditions for $PM_{2.5}$, and the Additional Statement of Basis and supporting documents described Air Quality Impact Analysis for $PM_{2.5}$. This additional permitting analysis specific to $PM_{2.5}$ was the Air District's response to the comments that the surrogate policy is inappropriate and illegal and that a $PM_{2.5}$-specific analysis is required.[157]

At the time of the August 2008 Additional Statement of Basis, the Air District was aware that EPA would at some point be finalizing its designation of the Bay Area as not being in attainment of the 24-hour $PM_{2.5}$ NAAQS. The Air District therefore put forward two alternative proposals, depending on whether the non-attainment designation became effective before a final decision was made on permit issuance. (*See* discussion in Additional Statement of Basis at pp. 52-55.) First, in the event that the non-attainment designation did not become effective, the facility would remain subject to PSD permit requirements. In that case, the Air District proposed issuing a PSD permit covering $PM_{2.5}$, along with the other PSD pollutants, based on the PSD analysis in

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[156] The granting of reconsideration and the issuance of the stay were made by letter from the EPA Administrator dated April 24, 2009, and in a subsequent Federal Register Notice dated June 1, 2009 (74 Fed. Reg. 26098).

[157] The Air District disagrees that no permits should be issued as a result of the fact that ambient air in the Bay Area is not in compliance with the $PM_{2.5}$ NAAQS (24-hour). The Clean Air Act's permitting programs are set up to address concerns about compliance with these standards through appropriate permit conditions and permitting analyses. For areas that are not in compliance with an applicable NAAQS, the Clean Air Act's Non-Attainment NSR permitting requirements apply, which require all major new facilities and major modifications to (i) achieve the Lowest Achievable Emissions Rate for the pollutant involved and (ii) provide offsetting emissions reductions from old sources that will make up for the new emissions from the new source or modification (among other requirements). These permitting requirements, along with the planning requirements and other requirements applicable in non-attainment areas, are designed to ensure that the NAAQS will be achieved in such areas, even if new facilities are permitted in the meantime.

the Additional Statement of Basis. Second, in the event that the non-attainment designation became effective before final decision on permit issuance, the facility would cease to be subject to PSD requirements for $PM_{2.5}$ (at least as they relate to the 24-hour standard) and would instead become subject to EPA's non-attainment NSR permitting requirements in 40 C.F.R. Part 51, Appendix S. In that case, the Air District would leave the issue of $PM_{2.5}$ permitting to Appendix S, at least as it relates to the 24-hour standard. (But note that the Appendix S requirements would not be applicable to this facility in any event because its $PM_{2.5}$ emissions are below the Appendix S threshold of 100 tons per year.[158])

It is this latter scenario that has come to pass as of the time of final permit issuance: the Bay Area's non-attainment designation for the 24-hour standard became applicable December 14, 2009.[159] (The region remains attainment/unclassifiable for the annual standard, however, creating what the District refers to as a "split" attainment designation.) The Air District is therefore going ahead with the second proposed alternative in the final PSD permit. This alternative presents a further question, however, regarding whether the PSD permit must still satisfy PSD requirements for $PM_{2.5}$ for the annual standard under the "split" attainment designation. In the Additional Statement of Basis, the Air District proposed to address this "split" attainment designation by including $PM_{2.5}$ issues in the PSD permit with respect to the annual standard, since the region is still "attainment/unclassifiable" for the annual standard and PSD requirements apply in areas that are attainment/unclassifiable for a particular standard. The Air District solicited further input and comment from the public about whether this is the correct approach, or whether Non-Attainment NSR permitting under Appendix S supersedes PSD permitting such that facilities would be subject only to Appendix S permitting $PM_{2.5}$. The Air District did not receive any further comments during the second comment period objecting to its proposed approach. Air District staff did obtain an oral opinion from staff from EPA Region IX stating an opinion that Appendix S permitting supersedes PSD permitting for $PM_{2.5}$, but Region IX staff were not able to point to any definitive analysis to support this opinion as of the time of final permit issuance. The Air District is therefore conservatively assuming that PSD permitting for the annual standard remains in effect, at least until such time as it can be established that PSD permitting no longer applies for the annual standard in an area that has been designated as non-attainment for the 24-hour standard.

For these reasons, the Air District is treating $PM_{2.5}$ as subject to the final PSD Permit with respect to the annual $PM_{2.5}$ standard. This means that $PM_{2.5}$ emissions are subject to BACT permit limits under 40 C.F.R. section 52.21(j). The Air District is including such limits in the

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[158] Here, the facility is exempt from Appendix S because it will emit less than 100 tons per year of $PM_{2.5}$. (*See* 40 C.F.R. Appendix S, ¶ II.A.4(i)(a) (establishing 100 tpy threshold for regulation of Major Stationary Sources); *see also* Additional Statement of Basis at p. 55.) There are therefore no additional Clean Air Act regulatory requirements applicable beyond the PSD regulations, and no additional federal permit required beyond the PSD Permit. In addition, it is worth noting that if Appendix S were applicable here, any Appendix S requirements would be implemented through a Non-Attainment NSR permit, not through the PSD Permit.

[159] *See* Air Quality Designations for the 2006 24-Hour Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards, Final Rule, 74 Fed. Reg. 58688, 58709-11 (Nov. 13, 2009) (to be codified at 40 C.F.R. § 81.305).

final permit conditions as proposed in the August 2009 Draft Permit. (*See* Permit Conditions ¶¶ 19(h), 22(e), 23(e); *see also* Additional Statement of Basis at pp. 53-53 (discussing BACT analysis for $PM_{2.5}$).[160]) This also means that the facility is required to show that it will not cause or contribute to an exceedance of the $PM_{2.5}$ annual NAAQS or PSD increment. The Air District conducted such an analysis as described in the Additional Statement of Basis and supporting documentation, and found that it would not. (*See* Additional Statement of Basis at pp. 80-92.) Thus, to the extent that PSD requirements apply to sources of $PM_{2.5}$ emissions in areas with "split" attainment designations for the annual and 24-hour NAAQS, this facility and this PSD permit satisfy those requirements.

In addition, beyond the issues of PSD applicability for $PM_{2.5}$, the Air District also received comments on the specific BACT limit it proposed for PM_{10}/$PM_{2.5}$, which are addressed in the remainder of this Section VI; and on its Air Quality Impact Analysis review with respect to $PM_{2.5}$, which are addressed in Section XIII below along with the other issues regarding the Air Quality Impact Analysis that have been raised in public comments.

Comment VI.2. – Regulating Ammonia Slip as a Precursor to the Formation of Secondary Particulate Matter:

The Air District received comments stating that it should undertake a BACT analysis for ammonia slip as a particulate matter precursor, based upon the potential for secondary PM formation. The comments claimed that permits for other facilities have been issued with lower ammonia slip limits. The comments questioned the Air District's analyses in the Statement of Basis and Additional Statement of Basis finding that ammonia slip from the facility would not contribute to the formation of secondary particulate matter, suggesting that ammonia slip is in fact a significant contributor and should be therefore be subject to BACT. The comments suggested that the memorandum the District cited in support of its conclusion that the Bay Area is nitric-acid limited – on which the conclusion that ammonia will not cause significant secondary $PM_{2.5}$ formation was in part based – was specific only to the San Jose and Livermore areas and cannot be used to support a determination for the Hayward area. The comments also stated that Air District staff were reevaluating the District's conclusion that ammonia slip emissions do not contribute to secondary particulate formation as expressed in the earlier memorandum. The commenters claimed that a site-specific analysis of secondary particulate from ammonia slip is warranted in order to assess the potential for ammonia slip from this facility to contribute to secondary particulate matter formation. The comments also questioned the District's statement earlier in the permitting process that the potential impacts of ammonia slip emissions on the formation of secondary particulate matter within the boundaries of the San Joaquin Valley Air Pollution Control District are not known. In general, the comments suggested that the Air District should subject ammonia emissions to the BACT requirement as a precursor to secondary $PM_{2.5}$ formation.

[160] BACT is also required for NOx as a precursor to secondary $PM_{2.5}$ formation. The Air District addressed this requirement in the Additional Statement of Basis at p. 54 (noting that the NO_2 BACT analysis and conditions satisfies the BACT requirements for NOx as a precursor). The Air District did not receive any comments on this issue, and it is therefore finalizing the permit as proposed with respect to this issue.

Response: EPA has addressed the issue of regulating ammonia as a precursor to particulate matter in its recent $PM_{2.5}$ rulemaking. EPA established there that it presumes that ammonia is not a secondary particulate matter precursor and should not be included in the PSD BACT analysis. EPA did provide that states will have the discretion to include ammonia in particulate matter regulations when adopting their own SIP-approved NSR permitting programs, provided they can make a technical showing that ammonia will be a significant contributor to $PM_{2.5}$ concentrations. But until that time, while states are applying EPA's rules for particulate matter, EPA has established that ammonia is not to be included in the permitting analysis as a precursor to secondary PM formation. This is clear from the definition of "Regulated NSR Pollutant" in 40 C.F.R. Section 52.21(b)(50)(i), which includes several precursors but specifically excludes ammonia.[161] Based on this clear regulatory direction from EPA about what to include in a PSD BACT analysis for particulate matter, the Air District disagrees that it should or could apply BACT in this permit for ammonia based on the potential for secondary particulate matter formation.

Nevertheless, beyond these legal requirements excluding ammonia slip from federal PSD permitting, the Air District went ahead and examined the technical aspects of this issue further, both in response to these comments and because the District will need to consider whether ammonia should be included when it adopts Non-Attainment NSR regulations for $PM_{2.5}$. Secondary particulate matter formation is a complex process that is not fully understood at the present time. As EPA recently noted in its rulemaking on secondary particulate matter precursors, "[a]mmonia emission inventories are presently very uncertain in most areas, complicating the task of assessing potential impacts of ammonia emission reductions. In addition, data necessary to understand the atmospheric composition and balance of ammonia and nitric acid in an area are not widely available, making it difficult to predict the results of potential ammonia emission reductions."[162] Given this situation, it is difficult at this time to state with any degree of certainty that ammonia slip from the facility may cause significant secondary particulate matter formation. It would therefore not be possible to impose a BACT requirement for ammonia slip at this time – even if EPA's regulations gave the District the discretion to do

[161] EPA has established the same situation for Non-Attainment NSR permitting under Appendix S during the transition period while states are developing their own $PM_{2.5}$ Non-Attainment NSR permitting programs. "Regulated NSR Pollutant" is similarly defined under Appendix S to exclude ammonia as a particulate matter precursor. (*See* 40 C.F.R. Part 51, Appendix S, § II.A.31.iii.) These regulatory definitions in EPA's rules governing its NSR program provide that ammonia should be excluded as a particulate matter precursor when these rules are used. These definitions contrast with the provisions for states to adopt their own SIP-approved Non-Attainment NSR and PSD programs, which allow for states to regulate ammonia as a particulate matter precursor if they can show that ammonia will significantly contribute to secondary PM formation. (*See* 40 C.F.R. 51.165(a)(1)(xxxvii)(C)(4) (providing that ammonia can be included as a precursor to secondary formation when states adopt their own permitting programs, upon sufficient showing).) These issues are discussed in more detail in EPA's preamble to its final rule, where EPA explains its intention that ammonia is not to be included in PSD permitting but can be included in states' own non-attainment NSR permit programs where appropriate. (*See* 73 Fed. Reg. 28321, 28330 & 28347-49 (May 16, 2008).)

[162] 73 Fed. Reg. 28321, 28330 (May 16, 2008).

so – as EPA has made clear that it Federal PSD Permitting decisions should not be made based on potential impacts that are merely speculative in nature.[163] The Air District notes that the commenters' assertions about the areas in which the District's initial analysis could be made more comprehensive only highlight the uncertainties surrounding the issue of secondary Particulate Matter formation and the difficulty of concluding with any confidence that ammonia slip emissions from this facility will cause significant additional Particulate Matter impacts.

Furthermore, EPA has found countervailing considerations that would counsel against unnecessarily restricting ammonia slip emissions where it would not provide $PM_{2.5}$ benefits, in that ammonia neutralizes harmful acids in the atmosphere. As EPA explained in its recent rulemaking, "[a]mmonia serves an important role in neutralizing acids in clouds, precipitation, and particles. In particular, ammonia neutralizes sulfuric acid and nitric acid, the two key contributors to acid deposition (acid rain)." EPA cited this trade-off between the potential benefits and drawbacks of ammonia restrictions, as well as the uncertainties surrounding the formation of secondary Particulate Matter from ammonia emissions, in excluding ammonia from Federal PSD regulation.[164] The Air District is mindful of these issues and declines to depart from EPA's considered (and legally required) approach at this time, especially where there is no conclusive evidence that ammonia slip from this facility will be a significant contributor to Particulate Matter formation. The Air District will be examining these issues further as it adopts Non-Attainment NSR regulations to address $PM_{2.5}$ and does not intend to foreclose the potential that it may determine to include ammonia in those regulations based on further investigation into the secondary impacts of ammonia emissions. But based on the available evidence at this time it cannot conclude with certainty that ammonia slip from this particular facility will be a significant contributor to secondary particulate matter formation.

The Air District also considered the comments critical of the District's memorandum concluding that the Bay Area is nitric-acid limited and that additional ammonia emissions will therefore not cause significant additional secondary $PM_{2.5}$ formation.[165] The Air District disagrees that the evidence it evaluated from the San Jose and Livermore areas should necessarily be discounted simply because those are different locations than Hayward, and the commenters have not provided any information from which to conclude that there may be more available nitric acid in the Hayward area and in San Jose or Livermore. But beyond the conclusions in 1997 memorandum, the Air District has been continuing to evaluate the science and available data on the issue of secondary $PM_{2.5}$ formation, as alluded to in the comments. This further evaluation has generally confirmed (preliminarily at least) that the Bay Area is in fact nitric-acid limited – although it has shown that the secondary particulate formation mechanisms are highly complex and that the generalizations made in the 1997 memorandum the District relied on in the Statement of Basis and Additional Statement of Basis may in hindsight have been overly

[163] *See In re Three Mountain Power*, 10 E.A.D. 39, 57-58 (EAB 2001); *see also In re Sutter Power Plant*, 8 E.A.D. 680, 693-94 and n. 13 (EAB 1999).
[164] 73 Fed. Reg. 28321, 28330 (May 16, 2008).
[165] The memorandum at issue is the Sept. 8, 1997, Office Memorandum from D. Fairley to T. Perardi & R. De Mandel entitled "A first look at NOx/Ammonium nitrate tradeoffs" (hereinafter, "Ammonium Nitrate Memorandum", discussed on pp. 26-27 of the Statement of Basis and pp. 55-56 of the Additional Statement of Basis.

simplistic. The focus of the Air District's further evaluation has been a computer modeling exercise designed to predict what $PM_{2.5}$ levels will be around the Bay Area, given certain assumptions about emissions of $PM_{2.5}$ and its precursors, about regional atmospheric chemistry, and about prevailing meteorological conditions. This information was used to create a computer model of regional $PM_{2.5}$ formation in the Bay Area from which predictions can be drawn about how emissions of $PM_{2.5}$ precursors will impact regional ambient $PM_{2.5}$ concentrations. The Air District's report on its computer modeling exercise has not been finalized, but the draft report concludes that regional ammonium nitrate buildup is limited by nitric acid, not by ammonia.[166] The draft report does find that the amount of available nitric acid is not uniform but varies in different locations around the Bay Area, and consequently the potential for ammonia emissions to impact $PM_{2.5}$ formation varies around the Bay Area. Specifically, according to the draft report, the model predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes in ambient $PM_{2.5}$ levels of between 0% and 4%, depending on the availability of nitric acid, leaving open the potential that ammonia restrictions could form a useful part of a regional strategy to reduce $PM_{2.5}$.[167] The draft report therefore restates the general conclusion from the 1997 "first look" memorandum that the Bay Area is nitric-acid limited, although it finds that reductions in the region's ammonia inventory could potentially achieve reductions in $PM_{2.5}$ concentrations in areas that may have sufficient available nitric acid.[168] (The draft report cautions that its assumptions regarding the availability of nitric acid may be misleading, however, because of the preliminary nature of the ammonia emissions inventory used for modeling – a concern cited by EPA in excluding ammonia from PSD permitting.) Notably, the model predicts that Hayward area, like the Livermore and San Jose areas, has among the lowest levels of available nitric acid in the entire region, in the vicinity of 0.25 ppb or less.[169] This last finding suggests that the study from the 1997 "first look" memorandum regarding the Livermore and San Jose areas would be useful in assessing the situation in the Hayward area.

The Air District also used this model to attempt to estimate what the secondary particulate matter impacts would be from the Russell City facility. That analysis is discussed in connection with the PSD source impact analysis for this facility in Response to Comment No. XIII.B.3. below. As discussed there, the computer model predicted that emissions of all secondary particulate precursors from the facility will have a maximum additional impact on ambient $PM_{2.5}$ levels of 0.11 $\mu g/m^3$, which is not a significant additional impact given the relative size of the direct $PM_{2.5}$ impact and background levels in the area.

Thus, after evaluating this issue further based on all of the evidence before it, the Air District continues to conclude that the evidence at this stage shows that additional ammonia emissions from the Russell City facility will not make a significant additional contribution to secondary $PM_{2.5}$ formation. The Air District therefore continues to conclude that it would not be

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166 *See* BAAQMD, Draft Report, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Draft, Oct. 1, 2009), at p. E-3 & p. 30. The Air District anticipates issuing a final report shortly.

167 *See id.* at pp. E-3 – E-4.

168 *See id.* at p. 30.

169 *See id.*, Figure 17, p. 31.

appropriate to subject this facility to a BACT requirement for ammonia slip at this time, even if the federal PSD regulations did not prohibit it.

Finally, with respect to the comment regarding potential secondary particulate matter formation in the San Joaquin Valley from ammonia slip emissions from the proposed project, nothing in the comments suggests that Russell City facility will have any such impacts. First, there is little indication that ammonia emissions from Russell City could even reach the San Joaquin Valley in any significant amount. Moreover, the available evidence suggests that secondary $PM_{2.5}$ formation in the San Joaquin Valley is at least as limited by the lack of nitric acid, given the large amount of ammonia emissions associated with agricultural operations there. The Air District's computer model shows virtually zero available nitric acid there,[170] and at least one independent studies has reached the same conclusion.[171] Any ammonia emissions that did manage to reach the San Joaquin Valley would therefore not have anything to react with to form $PM_{2.5}$. For all of these reasons, the Air District finds this issue irrelevant to the question of whether ammonia slip from the Russell City facility should be subject to the BACT requirement.

For all of these reasons, the Air District has concluded that the Federal PSD BACT requirement does not require an analysis of ammonia slip emissions facility based on the potential for secondary $PM_{2.5}$ formation. The Federal PSD regulations specifically exclude ammonia from the PSD BACT requirement for $PM_{2.5}$; and in any event, the available evidence at this time is not developed enough to show that the ammonia emissions from this particular facility would be likely to contribute significantly to secondary $PM_{2.5}$ formation.

Comment VI.3. – Particulate Matter BACT Limit For Gas Turbines/HRSGs:

The Air District did not receive any significant comments on the Particulate Matter limits it proposed in the December 2008 Draft Permit during the first comment period. The Air District nevertheless reviewed the proposed limits of its own volition after the first comment period ended and determined that lower limits would be appropriate. As explained in the Additional Statement of Basis, based on further review of additional information, the Air District determined that a revised limit on Particulate Matter emissions from each gas turbine and heat recovery boiler train of 7.5 lb/hr would be appropriate. This emissions limit would include all filterable and condensable particulate emissions (*i.e.*, "front" and "back" half, respectively). This revised limit was based on a review of additional source testing data from a number of similar combined-cycle facilities, which showed average particulate emissions of 4.58 lb/hr, with a high of 10.65 lb/hr.[172] The Air District concluded that some of the higher test results may be

[170] *Id.*

[171] *See* Betty K. Pun & Christian Seigneur, Sensitivity of PM Nitrate Formation to Precursor Emissions in the California San Joaquin Valley, (Apr. 9, 1999) at pp. 2-4 (cited in *In re Three Mountain Power*, 10 E.A.D. at n. 22).

[172] Each source test result represents the average of multiple test runs (3 in most cases) performed on the same unit. For a summary of the source test results, see spreadsheet, "Summary of Filterable PM_{10}", submitted by B. McBride (Director, Environment, Health and Safety, Calpine Corporation) to B. Bateman (Director, Engineering/Toxic Evaluation, Air District), W. Lee (Senior AQ Engineer, Engineering/Permit Evaluation, Air District) and B.

attributed to anomalies in the testing and analytical methods, the influence of which may be mitigated by application of more rigorous quality assurance/quality control ("QA/QC") by the testing contractor or analytical laboratory. The Air District therefore concluded that it would not be appropriate to establish a compliance margin that would accommodate these high test results. Instead, the Air District discounted the highest 5% of the test results (4 of the 73), and concluded that a permit limit based on the remaining 95% would provide an appropriate compliance margin. This approach yields a permit limit of 7.5 lb/hr. The Air District also reviewed available permits for other similar facilities and did not find any lower permit limits. For these reasons, the Air District concluded that the appropriate BACT limit for $PM_{10}/PM_{2.5}$ for each gas turbine/heat recovery boiler train should be 7.5 lb/hr. The Air District also revised its proposed conditions for the daily and annual Particulate Matter limits accordingly.

The Air District published this revised BACT analysis and proposed limits in the Additional Statement of Basis, and received a number of comments on these issues during the second comment period. Some comments stated that the Air District had not adequately justified the revised proposed limit of 7.5 lbs/hr. These comments noted that the data on which the District relied showed PM emissions at other similar sources between 4.58 and 10.65 lb/hr, and that the District derived the 7.5 lbs/hr proposed permit limit because 95% of the data points were below that level and only 5% of the data points exceeded it. The comments stated that the District did not adequately explain why it chose the 95% cutoff level. The comments also stated that some facilities that the District evaluated showed emissions well below the 7.5 lb/hr proposed limit. The comments also criticized the Air District for using data from existing facilities in its BACT analysis, implying that new facilities should be able to achieve particulate limits lower than the performance of existing facilities. Some comments also stated that a facility proposed for Carlsbad will emit only 39 tons per year of PM, compared with 71.8 tons for Russell City.[173]

Nishimura (Supervising AQ Engineer, Engineering/Permit Evaluation, Air District), by email dated June 10, 2009.

[173] The Air District also received a communication after the close of the comment period stating that the Blythe facility has a lower PM_{10} limit and that the Russell City limit should also be lower. Since this communication was not received during the comment period, it does not constitute a formal public comment and the Air District is therefore not obligated to respond to it. The Air District has nevertheless reviewed the Blythe permit, which has a 6 lb/hr limit. The Air District notes, however, that the turbines at the Blythe facility are smaller than the Russell City turbines, and when size it taken into account the Russell City limit is effectively the same as the Blythe limit. The Blythe turbines are Siemens V84.3A combustion turbines rated at 1776 MMBtu/hr each. Russell City, but contrast, will have a capacity of 2238.6 MMBtu/hr per turbine/HRSG train. (*Compare* Blythe PSD Permit (EPA Region IX, "Authority to Construct Issued Pursuant to Prevention of Significant Deterioration (PSD) Requirements at 40 CFR § 52.21", PSD Permit Number SD 02-01, April 25, 2007, EPA Docket ID No. EPA-R09-OAR-2007-0723-0001), at p. 2 and p. 6, Condition D.2., *with* Russell City PSD Permit, Condition 19. Note that the Blythe PSD permit limit applies only to the turbines, whereas the Russell City limit applies to the turbine and HRSG duct burners.) When this size differential is taken into account, both of these permit limits allow for the emission of 0.003 pounds of PM per MMBtu of fuel consumed. Moreover, it appears that the 6 lb/hr limit was intended to apply as a 3-hour average, based on the CEC's analysis. Emissions in pounds per hour were estimated at between 6.4 and

Response: Particulate matter emissions from gas turbines vary considerably, based on a number of factors including the levels of sulfur and particulates in the natural gas the turbines burn and the amount of particulates entrained in the combustion air. Moreover, source test results can also vary considerably from test to test, in part because the standard test method, EPA Method 201A/202, was designed to measure higher particulate levels than are emitted by gas turbines. This high degree of variability among particulate matter emissions is evident from the test results the Air District reviewed. (*See* discussion in Additional Statement of Basis at pp. 51-52 and fn. 98.) The BACT limit must be established at a level that can accommodate this variability so that it is achievable by the facility. The Air District therefore established the proposed BACT limit at 7.5 lb/hr as the most stringent emissions rate that will actually be achievable, consistent with the BACT requirement. The Air District disagrees with the comments that this is an inappropriate method for establishing a BACT limit, and in particular disagrees that the limit must be set at the lowest emissions rate ever seen in a test result, or at the average emissions rate seen in a group of test results. To the contrary, the BACT limit must be established at a level that can accommodate all reasonably foreseeable operating and testing scenarios, and the Air District's PM limit does that based on all available evidence. The Air District also disagrees that it has not adequately explained how it arrived at the 7.5 lb/hr BACT limit, as the discussion in the Additional Statement of Basis, as expanded upon herein, clearly explains the source test results the Air District reviewed and the way the Air District used the 95th percentile level as a way to arrive at a BACT limit that the most stringent that will be achievable by the facility.

The Air District also disagrees with the comments that it should not rely on test results from existing facilities. Test results from facilities that are built and actually operating are an appropriate means to establish the emissions rate that current technology can achieve. Obviously, if there are indications that new technology that is available but has not actually been built and operated yet can achieve even lower emissions, that information would support imposing an even more stringent limit that what is achievable by facilities that have been built and are actually operating. But the comments did not provide any information about any such new technologies, and the Air District is not aware of any. The Air District therefore concludes that the emissions rates achieved by existing sources that the Air District reviewed are an appropriate basis for establishing the BACT limit.

With respect to the comments about the particulate matter limit for the proposed Carlsbad facility, as noted above in response to Comment IV.C.3. regarding the Carlsbad NOx limits, the reason why that facility will have lower annual emissions is that it will operate for only up to 4100 hours per year, whereas Russell City is permitted for operation all year long. The Air District reviewed the proposed Carlsbad particulate matter limit and found it to be 9.5 pounds per

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7.6. (See CEC Final Staff Assessment, Air Quality Table 6, p. 4.1-17, *available at* www.energy.ca.gov/2005publications/CEC-700-2005-007/CEC-700-2005-007.PDF.) The Air District therefore disagrees that the Blythe facility would provide a basis on which to impose a lower BACT limit for particulate matter. In addition, the facility has not yet been built so there is no test data available to indicate whether the facility is capable of achieving compliance with its permit limit.

hour, which is higher than the 7.5 pounds per hour the Air District is imposing here.[174] The Air District therefore disagrees that the Carlsbad facility warrants a lower particular matter limit.

Finally, the Air District also received communications outside of the formal comment period from power plant owner/operators who questioned whether a limit of 7.5 pounds per hour would be achievable over all operating scenarios. These interested parties stated that equipment manufacturers will not guarantee emissions performance at 7.5 pounds per hour. They also noted that some of the test results showed emissions above 7.5 pounds per hour, and stated that as an enforceable not-to-exceed permit condition the BACT limit needs to be set at a level that can accommodate all such test results. They stated that the Air District should not establish a BACT limit at less than 9.0 pounds per hour. The Air District acknowledges these points and is considering them, but ultimately does not need to make a definitive determination in response because the project applicant is willing to accept the 7.5 pound-per-hour permit limit. The Air District understands that equipment manufacturers will not guarantee emissions below 9.0 pounds per hour. Vendor guarantees are one important indicator of what emissions performance level is achievable for a BACT analysis, although the presence or absence of a vendor guarantee is not by itself determinative.[175] The Air District is also fully aware that some of the test results it review showed emissions above 7.5 pounds per hour, as discussed in the Additional Statement of Basis. The Air District agrees that the BACT limit needs to be established at a level that is achievable under all operating scenarios, but does not agree that a small number of test results over 7.5 pounds per hour necessarily means that a 7.5 pound-per-hour limit cannot be found to be achievable for purposes of BACT. The Air District is investigating these test results further to develop more information on this issue. It may be that the high test results were due to inherent uncertainties in the test method as discussed above, or because of upsets in facility operation that led to excessive particulate matter. Alternatively, it may be that the equipment cannot in fact ensure emissions below 7.5 pounds per hour under all foreseeable circumstances. The Air District will continue to evaluate this issue going forward. But for purposes of the Russell City permit, the District does not need to make a final determination of whether BACT for this type of equipment should be 7.5 pounds per hour, 9.0 pounds per hour, or some number in between. The project applicant has agreed to accept a permit limit of 7.5 pounds per hour, and that limit meets or exceeds BACT.

Comment VI.4. – Particulate Matter BACT Analysis for Cooling Tower:

The Air District also conducted a similar review of the BACT limits for particulate matter emissions from the cooling tower. As noted in the initial Statement of Basis, the cooling tower can contribute to particulate matter emissions through solids dissolved in the water used in the cooling system, which can be emitted in the water vapor exhausted through the cooling tower. Although the Air District did not receive any comments on the cooling tower limits during the initial comment period, the Air District conducted its own further analysis of Total Dissolved Solids ("TDS") data from the source of the proposed facility's cooling water, the City of Hayward's Waste Water Treatment Plant, which is adjacent to the proposed facility. Based on this analysis, the Air District concluded that the facility should be able to keep the TDS of the cooling water at 6200 ppm or below. The Air District therefore revised its proposed BACT limit for TDS downward from the initial 8000 ppm limit to a revised more stringent 6200 ppm limit.

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[174] Carlsbad Energy Center FDOC, *supra* note 134, at p. 8 Table 1a.
[175] *See* NSR Workshop Manual at p. B.20.

The Air District published this revised proposed BACT limit in the Additional Statement of Basis and invited further public comment. The Air District did not receive any further comments on the numerical TDS standard it proposed as the BACT limit. The District did, however, receive comments suggesting that it should be requiring the facility to use a dry cooling system instead of a wet cooling system as the BACT technology choice. These comments cited statements by the District in other contexts where the District noted that wet cooling involves fine particulate matter impacts and that dry cooling is preferable in this regard.[176]

Response: The Air District agrees that dry cooling systems are preferable in general from a criteria air pollution perspective because they do not have the particulate emissions that can result from wet cooling. In reviewing these comments about requiring a dry cooling system here, however, the Air District has been mindful that it cannot require an applicant to redesign its facility in a manner that alters inherent design elements or changes a fundamental purpose of the facility. Here, this facility was specifically designed from the very beginning to make use of recycled water from the City of Hayward wastewater treatment plant.[177] A central element of the project design is a tertiary treatment plant that will utilize the City's wastewater effluent and clean it further to enable it to be used for cooling purposes.[178] The benefit of being able to recycle the City's wastewater was also one of the reasons the City cited in agreeing to a property exchange that allowed the applicant to go forward with the project at its current location.[179] And the Energy Commission explicitly found that the ability to use recycled wastewater was an objective of the project when it initially approved the facility.[180] The use of a wet cooling system taking advantage of the City's wastewater is thus clearly an integral design element of the project. Moreover, it has clear environmental benefits and does not appear to be a design choice the applicant has made for reasons independent of air permitting. Under these circumstances, the Air District would be hesitant to conclude that it could require the applicant to redesign this

[176] The Air District also received a letter outside of the comment period stating that the District should require dry cooling as LAER ("Lowest Achievable Emissions Rate") for $PM_{2.5}$ because the Bay Area is non-attainment for $PM_{2.5}$. This letter is not a comment on the record that the Air District is required to respond to, but for the commenter's information the District points out that LAER is not a PSD requirement, and this facility is not subject to LAER for $PM_{2.5}$ in any event.

[177] *See* City of Hayward Agenda Report to Mayor and City Council from City Manager (Feb. 6, 2001) ("This site has been selected both because of the industrial character of the area, and its proximity to the [wastewater] treatment plant, as Calpine proposes to utilize recycled water as part of its operation"), available at: www.hayward-ca.gov/citygov/meetings/cca/rp/2001/rp020601-10.pdf; *see also* RCEC Application for Certification, *supra* note 18, at pp. 9-2 – 9-22 (noting that a key siting criteria for the facility was a "[l]ocation near a sufficient source of cooling water, preferably treated wastewater").

[178] Calpine originally proposed to construct an Advanced Wastewater Treatment Plant (*see* RCEC Application for Certification, *supra* note 18, at pp. 2-1, 2-13); it subsequently redesigned the facility to be a Title 22 Recycled Water Facility (*see* Russell City Energy Center, LLC, *Amendment No. 1* (Nov. 2006) at 1-1, available at: www.energy.ca.gov/sitingcases/russellcity_amendment/documents/owner/2006-11-17_RCEC_AMENDMENT.PDF).

[179] *See* City of Hayward Agenda Report to Mayor and City Council from City Manager (Oct. 11, 2005), available at: www.hayward-ca.gov/citygov/meetings/cca/rp/2005/rp101105-06.pdf.

[180] *See* 2002 Energy Commission Decision, *supra* note 17, at p. 17.

source to use dry cooling in this case, as it would disrupt one of the basic objectives of the proposed facility which is recycling the wastewater from the City's treatment plant.

Ultimately, however, Air District need not resolve this issue here because – regardless of whether the Air District could require the applicant here to change from a wet cooling system to a dry cooling system – the Air District would decline to require dry cooling as BACT in this particular case because of the ancillary environmental benefits from using a wet cooling system here. If the Air District were to undertake a BACT analysis and compare wet cooling and dry cooling as alternative feasible control technologies, it would select wet cooling for this facility in "Step 4" of the top-down BACT analysis because of the benefits associated with recycling the City of Hayward's wastewater, which would otherwise be discharged into the Bay. The facility's "Zero Liquid Discharge" plant will minimize potential harm to water quality in the vicinity of the Water Pollution Control Facility's outfall, where wastewater that has undergone secondary treatment would otherwise be discharged into the bay. Although the City's wastewater is treated before discharge, it still contains minor amounts of water pollutants that contribute to the overall pollution levels in the Bay. Elimination of such water pollution, even in relatively small amounts, contributes to the health of the Bay and is therefore a beneficial environmental effect. This conclusion is supported by the State Water Resources Control Board, which encourages power plants wherever possible to draw cooling water from wastewater that is already being discharged into surface water bodies.[181] The Air District has concluded that this net environmental benefit would support the choice of wet cooling over dry cooling for this particular facility, to the extent that the BACT analysis can even consider a redesign of the facility to change the cooling system.[182]

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[181] State Water Resources Control Board, "Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling", Resolution 75-58, adopted June 19, 1976), at 4-5. The project's use of secondary effluent from the Hayward's treatment plant is in accord with the goal of this Policy, which is "to protect beneficial uses of the State's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the State." (*Id*. at 1.) The Policy is clear in its preference for locating power plants near coasts to minimize impact on the quality of freshwater resources, fish and wildlife. (*Id*. at 3.)

[182] The Air District received some comments during the second comment period that were skeptical that using recycled cooling water from the City's wastewater treatment plant would actually provide environmental benefits. The comments stated that there may be adverse environmental effects by ceasing to discharge the water into the Bay; and that there may be adverse effects because of the energy needed to run the tertiary treatment plant needed to clean the water sufficient for use as cooling water, and because of the potential for pollution from the generation of that energy. The Air District disagrees that there would be a net environmental harm from using recycled water. The elimination of the wastewater discharge into the Bay will not have any detectible impact on overall water levels in the Bay. The amount of wastewater at issue is on the order of 4 million gallons per day, which will not even amount to a 'drop in the bucket' compared to the total volume of water in the San Francisco Bay. Regarding treatment of the water, even if the facility were to use water from some other source, it would still have to be treated to remove any impurities. There are no natural sources of water near the project location that are sufficiently clean to be able to be used without further purification.

In addition, beyond these important water quality issues, there are other ancillary environmental and energy impacts associated with dry cooling that further support the Air District's conclusion on this issue.[183] An air-cooled condenser would constitute a significant heat sink in the proposed facility's Rankine cycle, requiring 48 fans that would consume 7,250 kilowatts of electrical power. In contrast, the wet cooling tower requires nine fans, requiring only 1,314 kilowatts. While the use of an air cooled condenser would reduce the load required by the tertiary water treatment and Zero Liquid Discharge by approximately 2,850 kilowatts, the net result would still be a reduction in plant output of approximately 3,086 kilowatts, or slightly more then 3 MW, which would represent a net reduction in overall plant efficiency of about 0.3%. This additional 3,086 kilowatts of parasitic load would require approximately 21 MMBtu/hr to produce the same electric load to the grid, which would represent nearly an additional 2,500 pounds per hour of CO_2 (with a proportionate impact on criteria pollutants as well). An air-cooled condenser would also be taller and bulkier – 144 feet tall at its apex (compared to just under 58 feet for the cooling tower) and with a footprint of 88,440 square feet (compared to 61,133 square feet for the cooling tower) – and thus have a greater visual impact as well as a greater "downwash" impact. An air cooled condenser would have greater noise impacts due to its greater height and surface area, which would result in greater acoustic radiation of noise from the proposed facility to the nearby shoreline. These additional ancillary impacts would further support the choice of wet cooling over dry cooling for this particular facility.[184]

Comment VI.5. – Alameda County Public Health Department Letter in CEC Eastshore Proceeding:

The Air District received comments referring to a letter submitted by the Alameda County Public Health Department submission in the CEC proceeding for the proposed Eastshore Energy Center requesting the CEC to postpone approval of new power plants pending further study and understanding of the health impacts of fine particulate matter.

Response: The Air District acknowledges the County's submission in the Eastshore Energy Commission proceeding. In the Commission's Russell City proceeding, the Commission considered all of the evidence before it, including evidence based on particulate matter impacts, and concluded that it was appropriate to approve the Russell City project under the circumstances. It is not the Air District's role to second-guess the Energy Commission's determination on this issue. As far as the Federal PSD Permit is concerned, the Air District has evaluated particulate matter impacts as explained in the Statement of Basis, in the Additional

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[183] *See* "Evaluation of Dry Cooling for the Russell City Energy Center", Alex Prusi, P.E., Calpine Director of Engineering, October 22, 2009.

[184] The Air District also received comments regarding the potential for the wet cooling system to cause outbreaks of Legionnaire's disease. These comments were not specifically directed to the issue of whether dry cooling should be required instead of wet cooling, but the Air District considered this issue as a potential ancillary impact associated with wet cooling. As explained below in Section XIV regarding health risks, however, the Air District found that there would not be any significant risk of Legionnaire's disease from the wet cooling system. (*See* Response to Comment XIV.5. below.) The Air District therefore concluded that this concern would not rule out wet cooling as a BACT control technology.

Statement of Basis, and in these Responses to Comments. Nothing in the County's submission suggests that the Air District's Federal PSD analysis is incorrect with respect to these issues.

Late Communication Regarding Particulate Matter Test Methods:

The Air District also received a communication after the close of the second comment period stating that the permit does not specify the test methods that will be used for annual stack testing in the permit itself. The letter claimed that identification of the test method was critical for PM_{10} and $PM_{2.5}$ because the magnitude of emissions is determined by the method used to measure them.

Discussion: Since this communication was not received during the comment period, it does not constitute a formal public comment and the Air District is therefore not obligated to consider or respond to it. The Air District would nevertheless like to take this opportunity to reassure the public that the facility will use the latest and most accurate testing methods for all source testing. The testing conditions require that the facility submit its test protocol to the Air District in advance for District review and approval, in order to ensure that the testing will be conducted in accordance with the requirements of the Air District's Manual of Procedures.[185] The testing requirements for particulate matter explicitly contemplate that it may become appropriate to use alternative measuring techniques to measure condensable PM such as use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds, but these alternative techniques can be used only upon obtaining approval from the Air District. The Air District has written the condition this way to allow the facility to propose use of a new test method currently under development by EPA and the American Society of Testing and Materials, should the new method become available during the facility's operating life. If the data obtained from use of this method should demonstrate that much lower levels of PM are actually emitted than reported by the current standard test method, such data would support imposition of lower BACT limits on future proposed sources. The Air District also notes that the Environmental Appeals Board has approved of source testing requirements imposed in this manner, with a requirement that the facility submit a source test protocol for review and approval by the permitting agency.[186]

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[185] *See* Bay Area Air Quality Management District, Manual of Procedures. The Air District's Manual of Procedures sets forth specific testing protocols for source testing for a number of pollutants, including particulate matter.

[186] *See In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 236 (EAB 2000) (rejecting claim that source test requirements were impermissibly vague for not specifying the specific conditions under which the testing must be conducted, where source test protocol would be subject to review and approval by the permitting agency).

VII. SO_2 ISSUES

<u>Comment VII.1 – Carlsbad SO_2 Emissions Limits:</u>

The Air District also received comments stating that the proposed Carlsbad Energy Center will emit only 5.6 tons per year of SO_2, compared with 12.2 tons for Russell City.

Response: The facility's SO_2 emissions are below the Federal PSD significance threshold and thus the PSD requirements do not apply to SO_2.[187] SO_2 emissions are therefore not relevant to the PSD permitting analysis. Nevertheless, the Air District reviewed the Carlsbad SOx limits in response to these comments. These comments incorrectly cited the amount of SOx that the Carlsbad facility will emit. The Final Determination of Compliance indicates that it will emit up to 16.9 tpy of SO_2, which is substantially more than the 12.2 tpy that the Russell City facility is expected to emit.[188] The Air District also notes that the Carlsbad facility will be permitted to operate only 4100 hours per year, whereas the Russell City facility will be permitted to operate throughout the entire year, as discussed in Response to Comment IV.C.3. above.

[187] *See* 40 C.F.R. 52.21(b)(23)(i) (40 tpy significance threshold). In addition, note that SO_2 is now also PSD-regulated as a secondary particulate matter precursor, but the significance threshold is the same as for SO_2 as a pollutant in its own right. *See* 73 Fed. Reg. 28321, 28327, 28349 (May 16, 2009).

[188] *Compare* Carlsbad Energy Center FDOC, *supra* note 134, at p. 13 Table 31, *with* December 8, 2008, Russell City Statement of Basis, at p. 14.

VIII. STARTUP AND SHUTDOWN ISSUES

The Air District received a number of comments on the proposed BACT startup and shutdown emission limits and District's technical analysis supporting them. In response to these comments, the Air District has reviewed the proposed startup limits and is lowering several of them as summarized in Table 3 below. The Air District published a revised Draft PSD permit in August of 2009 proposing these revised limits and received further public comment during the second comment period. The Air District is now finalizing the revised startup and shutdown limits as proposed and the August 2009 revised draft. The Air District's responses to all of the comments on these issues, in both comment periods, are set forth below.

A. Applicability Of BACT Requirement To Startups And Shutdowns

The Air District received some comments about the applicability of BACT generally for startups and shutdowns, and about whether the Air District's approach to BACT for these operating modes was appropriate.

Comment VIII.A.1. – Applicability of BACT to Startups and Shutdowns:
The Air District received comments disagreeing with its position that the stringent BACT limits proposed for normal operations would not be achievable during startups and shutdowns. The comments claimed that the permit needs to include BACT limits for all operating modes, and cannot exclude startups and shutdowns from the BACT requirement. In this context, the commenter cited the Environmental Appeals Board's decisions in the *Indeck-Niles Energy Center* case (in which the EAB observed that the petitioner had failed to raise the issue of whether the permit should have imposed short-term BACT emission limits for startup and shutdown emissions) and the *Tallmadge Generating Station* case (in which the EAB held that that PSD permits need to include BACT limits for startup and shutdown events).

Response: The Air District agrees that BACT is applicable to and required for startup and shutdown operations. The Air District's analysis and permit limits are consistent with the cited EAB precedents and other authorities regarding BACT. These comments appear to have misunderstood the District's point that the specific BACT limits imposed for normal operations are not achievable during startups and shutdowns. That point does not mean that BACT does not apply during startups and shutdowns, it simply means that different limits specific to those operating periods (and achievable during those periods) must be imposed.[189] The Air District published this further clarification of its position in the Additional Statement of Basis and invited members of the public to comment on it further if there any members of the public who continue to believe that the Air District is not including permit limits applicable to startup and shutdown operation. The Air District did not receive any such comments during the second comment period.

[189] *See In re Indeck-Niles Energy Center*, PSD Appeal No. 04-01, slip op. at 14-15 (EAB Sept. 30, 2004).

Comment VIII.A.2. – Inclusion of Startup Limits as Enforceable Permit Conditions:
The Air District also received comments that understood that the Air District had conducted a BACT review for startups and shutdowns, but contended that the BACT limits on startup and shutdown duration are not included in the permit conditions.

Response: In response to these comments, the Air District refers the commenters to the definitions of startup and shutdown. Startup and shutdown periods are defined with a maximum duration, and after the end of the startup and shutdown period the turbines have to comply with the more stringent emissions limits applicable during normal, steady-state operation. If the startup is not complete by the time the maximum startup duration has elapsed (*i.e.*, if the facility has not achieved normal, steady-state operation), the facility will have violated its permit conditions and will be subject to enforcement action. The Air District published this further explanation of how the startup and shutdown limits work in the permit conditions in the Additional Statement of Basis, and received no further comments on the issue during the second comment period.

B. BACT Limits For Startups

The Air District also received a number of comments during the initial comment period regarding the specific permit limits it proposed for startups and shutdowns. The District agreed with many of these comments, and in response it proposed reduced limits for several startup scenarios in the August, 2009, revised Draft PSD Permit and Additional Statement of Basis. In response to this revised proposal, the Air District received further comments during the second comment period. The Air District's responses to all of the comments received on issues concerning the startup permit limits, during both comment periods, are set forth in this section.

Comment VIII.B.1. – Stringency of Startup Emissions Limits:
Several of the comments received during the first comment period claimed that the Air District should impose more stringent emissions limits for startups. In support, these comments cited several facilities that they claimed establish that lower startup limits would be achievable for this facility. In particular, the commenters pointed to the Palomar Energy Center in Escondido, CA; the Lake Side Power Plant in Vineyard, UT; and the Caithness Long Island Energy Center in Brookhaven, NY, as facilities that they claim demonstrate that startup lower limits would be achievable as BACT here. The Air District had evaluated data from the first of these, Palomar, in the December, 2008, Statement of Basis (*see* Statement of Basis at pp. 41-42), but the comments claimed that additional data from the facility was available. Some comments stated that the Air District should require the specific technologies used at these facilities as BACT. Others stated that the Air District should establish a BACT emissions limit reflecting the same level of startup emissions reductions as achieved at these facilities, if it does not impose a requirement specifying the particular type of equipment to use.

Response: The Air District agrees with these comments that based on all of the available information, including the examples from these three facilities, the facility should be able to achieve lower BACT startup emissions limits than the Air District initially proposed in several areas. For NO_2 emissions, the Air District has concluded that the BACT limit for hot startups should be lowered from 125 lbs. to 95 lbs. based on further review of the emissions performance achieved by other facilities, including the Palomar Energy Center. For warm and cold startups, the Air District continues to believe that the NO_2 emissions limits it initially proposed are appropriate because the additional information it has reviewed supports these limits as the lowest that can reasonably be achieved over time. For CO emissions, the Air District has concluded that the emissions limits should be reduced from 5028 lbs. to 2514 lbs. for cold startups and from 2514 pounds to 891 pounds for hot startups. For warm startups, the Air District continues to believe that the CO limit of 2514 pounds initially proposed is the appropriate BACT limit. Table 3 below provides a summary comparison of the startup emissions limits the District initially proposed and the revised limits the District is now imposing in the final permit.

Table 3: Summary of Startup Emissions Limits –
Initial Proposal and Final Permit Limits

	NO_2 Emissions Limits (lbs/startup)		**CO Emissions Limits (lbs/startup)**	
	Initial Proposal	Final Permit Limit	Initial Proposal	Final Permit Limit
Hot Startups	125	95	2514	891
Warm Startups	125	125	2514	2514
Cold Startups	480	480	5028	2514

The Air District's further evaluation of the appropriate BACT startup limits, including its assessment of the three comparable facilities cited in the comments, is set forth in detail in the following paragraphs.

- ***Palomar Energy Center, Escondido, CA***

With respect to the Palomar facility, the Air District obtained additional emissions data that has been reported to the San Diego Air Pollution Control District (SDAPCD). This data included all NOx emissions data for the facility from October of 2006 through the end of 2007, and covers approximately 36 startup events involving the two turbines at the facility.[190] Although this is a fairly substantial amount of data, it is still somewhat of a preliminary picture of what the facility will be able to achieve over the long term given that it represents only a little over a year's worth of operation. Nevertheless, the Air District believes that it can use the data for what it is – an early indication of what startup NO_2 emissions this facility is likely to be able to achieve over time.[191]

[190] The Air District sought additional data since the end of 2007, but the facility has not reported any to the SDAPCD. The Air District also contacted the Palomar facility directly and requested review of additional data, but the facility declined and the Air District had no way to compel release of the data. (Telephone conversation between Alexander G. Crockett, Esq., BAAQMD, and Taylor O. Miller, Esq., Sempra Energy, 4/15/09.) In addition, the applicable permit limits for Palomar are of little help in evaluating the appropriate BACT permit conditions here, as they are much higher than those proposed for Russell City and the Air District does not consider them to represent BACT limits.

[191] Note that the startup limits in the permit for the Palomar facility are far higher than anything the Air District has considered for Russell City: 400 lbs/hr NO_x and 2,000 lbs/hr CO (and note that these limits are *hourly* limits, meaning that total emissions for an entire startup can be

The Air District has therefore analyzed all of this data, in conjunction with the startup data from other facilities it reviewed in its original analysis for the proposed permit, to refine its BACT analysis for startups in response to the comments received. The Air District's analysis was based on taking the raw, minute-by-minute CEM data from the facility and estimating when startups began and ended based on changes in O_2 concentrations. The Air District notes that the emission rates it arrived at through these calculations are somewhat lower than the emissions rates calculated by the SDAPCD for the four startups where SDAPCD calculations are available.[192] The Air District therefore concludes that its method is a conservative assessment of the actual emissions performance achieved during these events. The Air District also notes that it considered data only from after October 13, 2006, for turbine 1 and after October 12, 2006, for turbine 2, the dates on which the facility began to implement the full complement of efforts it has made to reduce startup emissions under a variance from the SDAPCD Hearing Board. The Air District excluded data from these dates and before because the comments that urged the Air District to consider the Palomar data asserted that it is the period after implementation of these efforts that evidences the best achievable startup emissions performance. Since the excluded data consist of, for the most part, data showing high emissions (for example, a cold startup event at turbine 1 on October 11, 2006, that produced 735 pounds of NO_2 emissions), the District's approach is, again, conservative.

Once the Air District collected and refined the data from Palomar, it broke the data out into cold, warm, and hot startups in order to compare it with the proposed Russell City limits.[193] (The Air District's summary of the Palomar data points is set forth in Appendix A to the Additional Statement of Basis.) Looking first at cold startups, the available data suggests that the Palomar facility is achieving cold startup emissions at levels very similar to the facilities on which the Air District based its initial proposed Russell City startup limits. The average NO_2 emissions for cold startups (defined as the turbine having been down for over 48 hours) were 182.8 pounds, which is very similar to the cold startup averages that the Air District reviewed for the Delta Energy Center and Metcalf Energy Center in the Statement of Basis, which were 193 pounds and 185 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). The highest NO_2 emissions during a cold startup at Palomar, on October 22, 2007, were 375 pounds according to the District's calculations or 437 pounds according to the SDAPCD's calculations, which again

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several times these hourly rates). (*See* Startup Authorization, SDG&E, 2300 Harveson Place, Escondido, CA 92029, San Diego County Air Pollution Control District, App. No. 984461, PO No. 976846, April 30, 2008, at Conditions No. 16-17.)

[192] The four startup events where SDAPCD calculations are available are the following:

Date	Turbine	SDAPCD Calculation	BAAQMD Calculation
12/10/06	1	26 pounds	22 pounds
10/22/07	1	285 pounds	225 pounds
12/23/06	2	115 pounds	111 pounds
10/22/07	2	437 pounds	375 pounds

In the following analysis, where data points are available from both the SDAPCD and BAAQMD calculations, both are given for the sake of completeness.

[193] Cold startups are startups when the turbine has been off-line for more than 48 hours; warm startups are when the turbine has been off-line for between 8 and 48 hours; and hot startups are when the turbine has been offline for less than 8 hours.

is similar to Delta and Metcalf, for which the highest cold startups were at 281 and 335 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). Based on this review, it appears that Palomar is performing at or near the level of the other similar facilities that the Air District considered in the Statement of Basis, but certainly not any better than that. The Air District concludes from this comparison that the Palomar data serve to confirm its earlier assessment of the appropriate cold startup limits for Russell City, and certainly do not suggest that the initial analysis was inaccurate.

The Air District did observe that the Palomar data showed a maximum startup emissions event of 375 or 437 pounds (depending on which calculation is used), which is somewhat below the proposed Russell City cold startup limit of 480 pounds. But the Air District does not consider this level of compliance margin – which is 9%-22% of the permit limit, depending on whose calculation is used – to be unreasonable for several reasons. First, the data from Palomar includes only five available data points for cold starts, which does not generate a great deal of statistical confidence that the maximum seen in this data set is representative of the maximum that can be expected over the entire life of the facility. Moreover, the wide variability in the data that is available highlights the variability in individual startups, underscoring the need to provide a sufficient compliance margin to allow the facility to be able to comply during all reasonably foreseeable startup scenarios. For both of these reasons, the Air District has concluded that a cold startup limit of 480 pounds of NO_2 is a reasonable BACT limit that is consistent with the startup emissions performance seen at the Palomar facility.

The Air District next reviewed the warm startup NO_2 emissions data from Palomar. The available Palomar data show NO_2 emissions from warm startups ranging as high as 111 pounds, or 115 pounds according to SDAPCD's calculations (on December 23, 2006). This is just 14 pounds (or 10 pounds according to SDAPCD) below the proposed warm start limit of 125 pounds, or 11% (or 8%) of the proposed limit. The Air District concludes from this evidence that the proposed limit is at least as stringent as could consistently be expected at Palomar. It is statistically unlikely that the highest-emission startup event over the lifetime of the facility would occur during the first 14 months of available data, and it is therefore reasonable to anticipate that emissions could be even more than 111 pounds (or 114 pounds) during certain warm startups. A compliance margin of an additional 11% (or 8%) over the maximum observed over the first 14 months of data at Palomar is not unreasonable, and is appropriate to accommodate the variability in emissions among startup events over time. The Air District therefore finds no basis in the Palomar warm startup data to impose a more stringent NO_2 limit than the 125 pounds-per-startup limit it initially proposed.

Third, the Air District reviewed the hot startup NO_2 emissions data from Palomar. The data the Air District reviewed showed a startup designated as "regular" startup with NOx emissions of 145 pounds (May 1, 2007). "Regular" startups presumably indicate hot starts, as that is the most normal and frequent type of startup at the facility,[194] but the Air District finds it questionable as to whether this was actually a hot startup (*i.e.*, occurred when the turbine was down for less than 8 hours). Taking the data without this apparent outlier, the Palomar startup data show average

[194] The Palomar facility most commonly operates during the day and shuts down overnight, so its most common startups are after less than 8 hours of down-time.

NOx emissions of 30.3 pounds and a maximum startup event of 75 pounds (November 27, 2006). Looking at the average startup emissions, it appears that Palomar is actually experiencing *higher* average hot startup emissions than the Delta Energy Center on which the Air District based its initial startup limit evaluation. The average hot startup NO_2 emissions for the years 2005 through 2008 at Delta were 25, 26.6, 27.6, and 29.8 pounds respectively, which are all better than the 30.3 pound average at Palomar (and much better than the average of 38.5 pounds if the May 1, 2007 outlier startup is included). Looking at the highest reported startup events, the data from Palomar show a high similar to the highest high at Delta, although a little lower. The highest hot startup seen at Delta was 82.2 lbs, which is slightly higher than the 75 pound startup event at Palomar on November 27, 2006 (although still much better than the 145-pound outlier event of May 1, 2007). The Air District has therefore concluded that for hot startups, the Palomar facility is not achieving an overall startup emissions performance any better than the other comparable facilities the Air District evaluated in establishing the proposed BACT limits. In further considering all of this data, however, the Air District has concluded that a somewhat more stringent compliance margin would probably be achievable here for hot startups. At the 125-pound hot-start limit initially proposed, the compliance margin would be 43 pounds more than the highest data point found at Delta and 50 pounds more than the highest data point from Palomar. The Air District is therefore lowering the NO_2 limit for hot starts in the final permit to 95 pounds per startup. This lower limit will bring the permit limit more in line with the high-emissions startups that have been seen at other similar facilities, while still providing an appropriate margin of compliance to take into account the fact that startups are by their nature highly variable and the highest startup emissions seen in the data collected to date may not necessarily reflect the highest emissions that would reasonably be expected under all circumstances over the life of the facility.

In summary, the Air District agrees with the comments that the additional NO_2 startup data from Palomar shed more light on what level of startup emissions should be achievable at Russell City. The Air District reviewed the additional data and found that Palomar has so far been achieving emissions rates very similar to the facilities on which the Air District based its proposed limits. Based on its review of this data, the Air District has concluded that Palomar confirms the Air District's initial assessment in the Statement of Basis with respect to cold and warm startups, but provides evidence with respect to hot startups that the emissions limit can be reduced from the proposed 125 pounds to 95 pounds per startup. With this revised hot startup limit, the Russell City permit limits align very closely with the startup emissions seen at Palomar based on the available data, as summarized in Table 4 below:

Table 4: Comparison of Palomar Startup NOx Emissions Data to Russell City NOx Startup Limits

	Palomar 14-Month Maximum*	Russell City Permit Limit
Hot Startup	75 pounds	95 pounds
Warm Startup	111/115 pounds**	125 pounds
Cold Startup	375/437 pounds**	480 pounds

*excluding startups that occurred before implementation of startup emissions reduction measures.
**BAAQMD/SDAPCD calculations, respectively

- ***Lake Side Power Plant & Caithness Long Island Energy Center***

The Air District also reviewed the Lake Side Power Plant and Caithness Long Island Energy Center, the other two facilities that the commenters cited. The commenters discussed these two facilities primarily in the context of using an emerging startup technology – the "Fast-Start" once-through steam boiler design – in order to reduce startup emissions. As explained in greater detail in the startup technology section below, the Air District investigated these facilities further and found that they do not use Fast-Start technology, although the do utilize an auxiliary boiler that can have a startup emissions benefit. Nevertheless, they are similar combined-cycle facilities and the Air District evaluated whether they are achieving better startup performance.

The only way to compare the Lake Side and Caithness facilities is based on their startup permit limits, as there is no published data from either facility because they are only just coming online. The Caithness facility has not yet been built, while the Lake Side facility has been operating only since December of 2008, as some comments pointed out, and the Air District is not aware of any actual operating data that is available for it (nor have any of the comments pointed to any). Without actual operating data available for review, the Air District compared the permit limits for those facilities to see whether they suggest that lower permit limits might be appropriate for Russell City.

First, for Lake Side, the facility's permit has *no* limits whatsoever on emissions during startups.[195] The Air District does not believe that it would be appropriate to issue a permit for the Russell City Energy Center without limits on startup emissions, as discussed above. But to the extent that commenters contend that the Air District should look to Lake Side as a comparable facility, there are no startup limits to compare.

For Caithness, the permit does have emission limits for startups, and it is therefore possible to compare those limits with the Russell City permit limits.[196] The Caithness permit establishes two tiers of startup limits, one for when the auxiliary boiler is being used and one for when the auxiliary boiler is not being used. The Air District evaluated the limits for startups without the auxiliary boiler, which is the scenario corresponding to the design of the Russell City facility.

[195] Utah DEQ Approval Order DAQE-AN3031001-05 (Lake Side Power Plant), Conditions 9 & 12 (available at www.airquality.utah.gov/Permits/DOCS/AN3031001-05.pdf.) The permit does contain daily emissions limits, towards which startup emissions are counted, but has no limits specifically for emissions during startups. In addition, the permit application provided startup information based on vendor data, which were referenced in the Utah DEQ analysis for the permit, but these numbers were for one specific operating temperature and were not presented as vendor guarantees of what the equipment could reliably achieve under all foreseeable operating circumstances. Moreover, the numbers do not identify whether they were for startups using the auxiliary boiler or not. (*See* Notice of Intent and Prevention of Significant Deterioration Air Quality Application, Lake Side Power Plant (May 2004), Table 3-6.)

[196] *Prevention of Significant Deterioration of Air Quality (PSD), Caithness Long Island Energy Center*, April 7, 2006 (with transmittal letter from W. Mugdan, Director, U.S. EPA Region 2, Division of Environmental Planning and Protection, to R. Ain); available at: www.caithnesslongisland.com/Final%20PSD%20Permt_4.7.06.pdf.

For NO_2 emissions, the Caithness startup limits are all higher than the limits the Air District initially proposed for the Russell City permit here. The Air District therefore concludes that Caithness further supports the reasonableness of these NO_2 startup limits as the lowest achievable BACT limits. At the very least, the Caithness permit cannot be read to suggest that lower NO_2 startup limits are warranted. The story is slightly different for CO startup emissions, however, as the Caithness permit limits for hot and cold startups are below the CO startup limits the Air District initially proposed for Russell City. Specifically, the Caithness hot startup limit for CO (without auxiliary boiler) is 891 pounds, which is significantly lower than the 2514 pound CO hot startup limit initially proposed for Russell City. Further, the Caithness cold startup limit for CO (without auxiliary boiler) is 2813 pounds, which is significantly lower than the 5028 pound CO cold startup limit initially proposed for Russell City. Upon further consideration, the Air District believes that revisiting the proposed Russell City limits for hot and cold startups would be appropriate in light of this new information from Caithness. The Air District is therefore lowering the hot startup limit to 891 pounds of CO, based on the limit imposed in the Caithness permit for similar equipment. The Air District is also lowering the cold startup limit to 2514 pounds of CO, based on the Caithness permit and on another lower permit limit the Air District examined in further considering this issue, the Sutter Power Plant. The Sutter facility has a permit limit of 2514 pounds of CO per cold startup and has been achieving this limit, and the Air District concludes that a 2514 pound limit would be achievable at Russell City as well.[197]

Based on this review, the Air District has concluded that the Russell City startup limits will be as stringent as (or more stringent than) either Lake Side or Caithness for startups without an auxiliary boiler. For ease of comparison, the Lake Side, Caithness and Russell City permit limits are summarized in Table 5 below.

Table 5
Comparison of Lake Side, Caithness and Russell City
Startup Emissions Limits (without Auxiliary Boiler)

Startup Scenario	Lake Side Permit Limit	Caithness Permit Limit	Russell City Permit Limit
Hot Startup	n/a	127 lbs. NOx	95 lbs. NO_2
	n/a	891 lbs. CO	891 lbs. CO
Warm Startup	n/a	488 lbs. NOx	125 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO
Cold Startup	n/a	488 lbs. NOx	480 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO

[197] *See* California Energy Commission, *In the Matter of Calpine Construction Finance Company, L.P.'s Sutter Power Project, Order Approving Amendment to Change Startup Emission Limits and Other Air Quality Conditions*, Docket No. 97-AFC-2C, Order No. 03-0611-01(k), June 11, 2003, p. 9, available at: www.energy.ca.gov/sitingcases/sutterpower/compliance/2003-07-24_APRVNG_AMNDMNT.PDF.

The Air District also considered the possibility of requiring an auxiliary boiler, which would presumably be able to achieve lower emissions limits similar to those expressed in the Caithness permit applicable when the auxiliary boiler is used. Upon further consideration of this issue, the Air District has concluded that while auxiliary boilers are common technology in colder climates to keep equipment warm in cold weather, the costs associated with requiring such equipment at Russell City would not be justified by the relatively small startup emissions reductions that would be gained. (*See* discussion in Response to Comment VIII.C.4. below for the complete analysis.) The Caithness permit limits for this operating scenario are therefore not comparable to Russell City and the Air District does not consider them as indicative of what the Russell City facility will be able to achieve.

In summary, the Air District agreed with the comments it received that it should examine the Palomar, Lake Side, and Caithness facilities as comparable facilities to determine if the startup limits in the Russell City permit are the lowest achievable. As outlined in the foregoing discussion, the conditions that the Air District is imposing in the final permit are the most stringent achievable based on a review of these facilities as well as all other available data.

The Air District published this further analysis and the lowered startup limits in the August 2009 Draft Permit and Additional Statement of Basis and invited further public review and comment. During the second comment period, the Air District received comments criticizing the proposed NO_2 limits for cold and hot startups. For cold startups, the comments criticized the proposed limit of 480 lbs/startup and stated that the other similar facilities that the District evaluated show average startup emissions in the range of 183 to 193 pounds. These comments stated that the proposed limit of 480 pounds is in fact the second-highest emissions data point from the Sutter facility. Similarly, for the hot startup NO_2 limit of 95 pounds, the comments stated that the Air District should base the permit limit on the average emissions performance of other similar facilities, which they claimed was 25 to 29.8 pounds, and that it was improper to look to the maximum emissions associated with startups instead of the average. These comments further stated that the Air District has not adequately explained the basis for the compliance margin provided in these limits.

In response to these comments, the Air District disagrees that the BACT limits should be based on the average startup emissions performance observed at other similar facilities. The BACT limits will be enforceable, not-to-exceed permit limits that the facility will be required to comply with at all times and under all foreseeable operating conditions, not just during average startups. The limits therefore need to allow for a sufficient compliance margin to accommodate all reasonably foreseeable startups, not just the average case. The Air District took this requirement into account in deriving the startup limits, as explained in the Statement of Basis, Additional Statement of Basis, and the further analysis described above. As explained above, the 480-pound cold-startup limit was based on early data from the Palomar facility showing emissions could be as much as 375-437 pounds for a cold startup, with a reasonable additional compliance margin to allow for the fact that startups are highly variable in nature and that the 375-437 pound startup emissions seen in the Palomar data may not necessarily be the highest startups the facility will experience over its lifetime. Similarly, the 95-pound hot-startup limit was based on the Palomar data showing hot startup emissions of up to 75 pounds (excluding the 145-pound data point as an apparent outlier) with a reasonable compliance margin. The Air District believes that this is a reasonable and appropriate approach to implementing not-to-exceed BACT limits that are the lowest achievable under all operating situations. The Air District disagrees with the comments that this approach is unreasonable for the reasons stated above. The Air District also disagrees with the comments that it has not adequately explained how it came up with these limits, as the District's analysis was clearly set forth in the Statement of Basis (pp. 38-47) and Additional Statement of Basis (pp. 58-74), and has been further clarified in this document.

Comment VIII.B.2. – Limits On Startup Duration:

The Air District also received some comments suggesting that the length of time it proposed to allow for startups is longer than it needs to be. The comments criticized the Air District's reliance on the startup limits for the Delta, Los Medanos, and Metcalf Energy Centers and the Sutter Power Plant in its analysis of the appropriate startups limits for Russell City, claiming that these facilities may not represent the best startup times achievable today using best work practices. The comments argued that the Air District must evaluate whether shorter startup timeframe would be achievable using best work practices, and cited one recent permit – for the Colusa Generating Station in Colusa, CA – that had been issued with shorter startup time limits of 4.5 hours for cold startups (compared with 6 hours proposed for Russell City) and 1.5 hours for hot startups (compared with 3 hours proposed for Russell City).[198]

Response: The Air District disagrees with these comments that BACT requires shorter startup limits, because (i) BACT requires permit conditions to limit *emissions*, and does not require a limit on startup durations as long as the *emissions* involved are limited to the greatest extent achievable; and (ii) even if BACT does require a limit on startup time periods, there is no indication in these comments that a shorter duration than the Air District proposed would be achievable.

1. Applicability to BACT to Startup Duration (as Opposed to Startup Emissions)

At the outset, the Air District notes that startup duration, as opposed to startup emissions, is not technically subject to the BACT requirement. BACT is "an *emission limitation* . . . based on the maximum degree of *reduction for each pollutant*" achievable by the facility (40 C.F.R. § 52.21(b)(12) (emphasis added)). It is thus a limitation on the amount of pollution emitted, not on the duration of any particular operating mode. As long as a facility can achieve the lowest *emissions* from startups among sources of its type, the facility will satisfy BACT even if it has to take a longer *time* to get to steady-state operating conditions. The reason for this rule is obvious: it is the emissions that matter from an air quality standpoint, not the time involved, and so if two facilities can achieve the same emissions performance there is no air quality reason to prefer one startup duration over the other (and indeed if one can achieve lower total emissions but needs a longer time frame to do so, the longer lower-emissions startup should be encouraged). The Air District has traditionally included startup duration among its permit conditions because as a

[198] Note also that some of the comments on this subject cited emerging technologies that they claimed can reduce startup times, which are addressed in the technology choice section below. This Response focuses on the startup time limits that can be achieved using best work practices, without additional technologies that the Air District is not requiring as BACT because of the reasons outlined below.

general rule shorter startups equate to lower startup emissions, but as long as the emissions rates are at the lowest level achievable the facility will satisfy BACT regardless of duration. Here, the Air District's evaluation has concluded that the Russell City Energy Center will be subject to the most stringent achievable startup *emissions* limits as explained in the initial Statement of Basis, the Additional Statement of Basis, and these Responses to Comments, and so the facility satisfies the BACT requirement on that basis. Imposing an additional requirement on startup durations is not technically required by BACT.

The Air District published this further legal analysis in response to these comments in the Additional Statement of Basis, and received further comments on the issue during the second comment period. These further comments questioned the Air District's conclusion that startup durations are not technically subject to BACT requirements, as opposed to startup emissions. The comments did not cite any support in the BACT definition in the PSD regulations or in any EPA guidance. Instead, they challenged the District's argument that BACT requires achieving the lowest *emissions* limit as opposed to the shortest *duration* simply by asserting that shorter startups will involve lower emissions. But this argument actually supports the Air District's conclusion, as it tacitly agrees that what is ultimately important is emissions. The commenters' goal here is thus the same as the Air District's – to achieve the lowest emissions from a startup. If the permit limits achieve that goal, they satisfy BACT even if there is no limit on startup duration.[199] Ultimately, however, this issue is moot because the District *is* imposing enforceable BACT permit limits on startup durations in the permit, as discussed below.

2. Derivation of Startup Duration Limit

Beyond this threshold point regarding BACT applicability, the Air District has in response to these comments considered further whether current best practices can achieve shorter startup times than what was achievable by the facilities that it reviewed in the Statement of Basis, which as the comments pointed out were permitted pre-2001. The Air District has concluded from this review that there is no reliable evidence that they can. The commenters did not cite any evidence of advances in best work practices since those facilities were permitted, and their criticism of the Air District's reliance on those facilities is based solely on the passage of time. Moreover, some

[199] The comments also questioned why, if BACT is ultimately focused on startup emissions and not startup duration, EPA Region 9 imposed permit conditions for the Colusa project with shorter startup durations (at least initially) than the Air District is requiring here. The only indication of why EPA Region 9 imposed initial limits startup on startup duration shorter than the Air District is imposing here is found in Region 9's Ambient Air Quality Impact Report. As discussed below in connection with the Colusa permit (*see* note 201 below), Region 9's explanation was that the applicant proposed such limits and they were lower than other permit limits Region 9 was aware of. The Air District does not find this to be conclusive evidence that the Colusa duration limits will be achievable, especially in light of Region 9's position that the limits may not be achievable and will have to be revisited if they are not. Moreover, the Colusa permit includes higher emissions limits than the Air District is requiring here, as explained below in footnote 201, and so the Air District is skeptical of basing its startup BACT analysis on the Colusa permit, especially where there are not yet any operating data from the facility to show exactly what level of performance the facility will be able to achieve.

of the commenters themselves cited contrary evidence, in the form of recent testimony before the California Energy Commission that using current technology, startups at combined-cycle facilities "can take a minimum of three and possibly six hours . . . ."[200] Based on this record, the Air District finds little compelling evidence that there have been any significant advances in operational practices in recent years that can reduce startup times.

The one recent permit the comments did cite on this issue is the Colusa permit, which the Air District reviewed in detail in response to these comments. Although that facility has not been built yet and so there are no actual operating data on which to assess its startup performance, the commenters are correct that the permit for the facility does include tentative initial time limits for hot and cold startups that are shorter than the Air District is proposing for Russell City, as noted above.[201] But even if the facility will be able to achieve steady-state operation within these time limits, that does not mean that it will achieve better startup performance. To the contrary, the startup limits for the Russell City Energy Center will be *lower* than for Colusa, notwithstanding Colusa's shorter time limits. Specifically, the Colusa permit allows up to 779.1 pounds of NO_2 per cold startup and 259.9 pounds of NO_2 per hot startup.[202] By contrast, Russell City will be limited to 480 pounds of NO_2 per cold startup and 95 pounds of NO_2 per hot startup, approximately half the amount allowed at Colusa.[203] The Air District therefore concludes based

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[200] *See* Comments on Draft PSD Permit on behalf of Citizens Against Pollution, Feb. 5, 2009, p. 11 (citing testimony before the California Energy Commission on December 18, 2008).

[201] Because the facility has not yet been built, there is no evidence from this facility on which to rely other than the analysis and justification in the permitting agency's BACT analysis. But that analysis does not include any actual operating data showing that these limits are achievable. To the contrary, it appears that the permitting agency concluded that the startup limits satisfied BACT because the applicant had proposed them and because they were below the limits in other permits for similar facilities. (*See* EPA Region 9, *Ambient Air Quality Impact Report, Colusa Generating Station*, PSD Permit No. SAC 06-01 (May 2008) (hereinafter, "Colusa Ambient Impact Report"), at pp. 19-20, available at www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436.) Moreover, the permitting agency explicitly considered that the startup limits might not turn out to be achievable, explaining that if experience shows that they are unrealistic then they will have to be revaluated. (*See id.*) The Air District therefore finds it highly questionable whether the Colusa example provides any hard evidence on which to conclude that the short startup limits in the permit are achievable. The issue is moot, however, as regardless of startup times the Russell City permit limits require lower emissions than the Colusa permit limits.

[202] *See* US EPA Region 9, Colusa Generating Station Final PSD Permit (Sept. 29, 2008) (available at www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436). The project owner has applied for certain amendments to the PSD Permit, but the proposed amendments would not affect the startup conditions. *See* Proposed Amended Permit Conditions, Colusa Generating Station, PSD Permit No. SAC 06-01, available at www.regulations.gov/search/Regs/home.html#documentDetail?R=0900006480a1ee9e (redline version showing proposed changes).

[203] The Air District notes that the Colusa startup limits for Carbon Monoxide are somewhat lower than the Russell City startup CO limits. (*See* Colusa Permit at www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-

upon its review of the Colusa permit that the Russell City permit limits do satisfy the Federal PSD BACT requirement.

The Air District published this further explanation and analysis in the Additional Statement of Basis and solicited further public comment. The Air District received comments during the second comment period further claiming that it had not justified its proposed limits on startup duration. These comments again pointed to the Colusa permit and claimed that it imposes shorter time limits on startups. The commenters stated that the Air District has not justified why it should not impose limits similar to those in the Colusa permit. In response to these further comments, the District disagrees that the Colusa permit conditions show that shorter startup times would be achievable here for all of the reasons provided previously. The feasibility of the Colusa startup duration limits was not verified by EPA Region 9 by any analysis to determine whether they will be achievable or not; they were simply proposed by the permit applicant and accepted by EPA.[204] Moreover, they were accepted as initial limits only, and will be subject to amendment "if source testing determines that these emission rates are not achievable".[205] The Air District therefore does not consider the issuance of this permit as sufficient demonstration that shorter startups can be achieved at Russell City in light of the countervailing information indicating that longer startups may sometimes be necessary.

Comment VIII.B.3. – Average Startup Limits:

The Air District also received comments stated that it should require cold-start NO_2 emissions to meet an overall average limit as well as a maximum limit for a particular startup event.

Response: The Air District considered these comments and has concluded that limits on the maximum emissions allowed during cold startups are sufficient to ensure compliance with the PSD BACT requirement. Startup performance is inherently highly variable, and it is difficult to ascertain with certainty what an achievable average emissions rate would be over a particular averaging period. Moreover, a maximum limit will force the facility to implement best work practices to minimize emissions during all startups, which will have the indirect effect of limiting emissions over a group of startups in a given period. And average startups limits are also

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2008-0436.) The fact that Colusa has higher NOx startup limits than Russell City in conjunction with lower CO startup limits highlights the NOx/CO tradeoff that the Air District noted in the Statement of Basis. The Air District does not agree with favoring reduced CO in exchange for increased NOx emissions because the Bay Area is in attainment of the applicable CO NAAQS but is non-attainment with the applicable ozone NAAQS (and NOx is an ozone precursor). The Air District therefore does not find that the Colusa permit provides evidence on which to justify a lower CO limit for startups. To the extent that the Colusa permit shows that lower CO startup limits are technically feasible, the Air District would reject them in favor of the limits it is imposing here based on the ancillary environmental impacts involved in going to those lower CO limits – that is, the increased NOx emissions that would be involved, as evidenced by the higher Colusa NOx limits. Moreover, the District also notes that the Colusa facility has not yet been built, and so there are no operating data available to show whether the facility will actually be able to achieve these limits.

204 *See* Colusa Air Quality Impact Report, *supra* note 201, at pp. 19-20.

205 *See id.* at p. 20.

indirectly limited by the annual limit on NO_2 emissions, which will encompass the emissions from all of the startups throughout a given year. For all of these reasons, the Air District declines to impose average limits on cold startup NO_2 emissions based on these comments. BACT will be adequately implemented by short-term emissions limits, which is the preferable type of BACT limit for Federal PSD permits.

Issue VIII.B.4. – Restriction on Simultaneous Startups of Both Turbines:

The Air District also realized that the proposed permit conditions did not include a restriction on both turbines being in startup mode at the same time. This is a common restriction designed to minimize short-term emissions. A restriction on simultaneous startups was imposed in the Energy Commission's license for this facility, but was inadvertently left out of the proposed PSD permit. The Air District did not receive any comments on this issue during either comment period, but is imposing this restriction in the final permit for the reasons stated above.

C. BACT Technology Review

The Air District also received a number of comments regarding its analysis of the control technologies available to reduce startup emissions. A number of comments criticized the Air District's BACT technology review, claiming that certain technologies the Air District rejected should be required because they would result in lower BACT permit limits. Among the technologies cited in these comments were Fast-Start technology, which is an integrated system using a "once-through" steam boiler to reduce startup times; the use of an auxiliary boiler to keep equipment warm during shutdowns and therefore allow it to start back up more quickly; and Low-Load "turn down" technology (a version of which has been installed at the Palomar facility discussed above), which aims to reduce emissions at lower loads and may potentially be effective to reduce emissions as the turbines ramp up to full load during startups. The Air District has further analyzed these technologies in light of these comments, as follows.

1. "Fast-Start" Integrated Once-Through Steam Boiler Technology

Comment VIII.C.1. – Potential For Using Fast-Start Technology With Highly Efficient Triple-Pressure Steam Turbine Generating Equipment:

The Air District received a number of comments regarding "Fast-Start" once-through steam boiler technology. This technology uses an integrated design that eliminates the need for a steam drum as part of the combined-cycle operation, among other design features. This design avoids many of the elements that limit the speed with which the system can start up, such as having to heat up the steam drum. The Air District evaluated the potential for using this technology here in the Statement of Basis (*see* pp. 39-40), but found that it is not currently available for the more-efficient triple-pressure steam turbine designs utilized by facilities such as this one. Fast-Start technology is currently available for less-efficient single-pressure operations in an application known as "Flex-Plant 10", which is appropriate for peaking-to-intermediate applications, but the Air District concluded that it would not be appropriate to require the facility to be redesigned to use such a system because it would be less efficient, among other reasons. An application for triple-pressure systems such as this one – known as "Flex-Plant 30" – is currently under development, but it is not yet available at this time.

The Air District published this analysis in its Statement of Basis and received comments asserting that "Fast Start" technology is available for combined-cycle facilities with higher-efficiency triple-pressure steam turbines of the type proposed for the Russell City facility. These comments claimed that the Siemens Flex-Plant 30 design is available and could be used for this facility. The comments cited two projects – the Lake Side Power plant in Utah and the Caithness Long Island Energy Center in New York – that they claimed use Flex-Plant 30 technology.[206]

Response: The Air District reviewed the situation regarding the availability of Fast Start technology in response to these comments. Siemens confirmed that no Flex Plant 30 has been constructed or proposed at this time for a full-scale power plant project. The term "Flex Plant" is used to describe a family of Siemens' combined cycle "platforms" based on integration of one or more Siemens' SGT6-5000F gas turbines, a Siemens integrated cycle design and HRSG specification, a Siemens steam turbine, and a Siemens SPPA-T3000 control system.[207] Siemens representatives have confirmed to the Air District that the Lake Side and Caithness facilities both use the same 501F turbine technology and conventional triple-pressure boiler technology as proposed for Russell City, *i.e.*, they do not include a "once-through" Benson boiler.[208] According to Siemens, "[n]either Lakeside [Power Plant] nor Caithness Long Island Energy

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[206] The Air District also received comments citing the District's observation in a footnote in the initial Statement of Basis regarding retrofitting the facility to be able to accommodate an integrated design, as well as statements elsewhere during the permitting process that the costs involved would make the project financially unviable and would be contractually unworkable. These comments asserted that concerns about costs and retrofitting were the basis for the District's determination not to require Fast-Start technology as BACT. These comments charged the District with basing its BACT determination on outdated technology instead of present-day BACT technology. The Air District disagrees with these comments. As explained above in Section II, the Air District is basing all of its BACT determinations on current technology. Moreover, the Air District has not taken the costs of Flex-Plant technology into account in its analysis of that technology, because it has concluded that it is not an available technology for this type of facility. The Air District's observations about costs in this regard were not something that was relied on as part of the BACT analysis. The only places where cost-effectiveness has been taken into account in the District's BACT analyses are specifically addressed in the relevant sections of this document.

[207] Siemens Statement Regarding Available Siemens Technology Which Appear in Comments on RCEC's Draft PSD Permit ("Siemens Technology Statement"), received by email from Candido Viega, Region Vice President, Pacific Northwest, Siemens Energy, Inc., to Richard Thomas, Calpine, March 16, 2009.

[208] *Id.* The BACT analysis performed by the Utah Department of Environmental Quality's, Division of Air Quality also suggests that the Lake Side Power Plant does not reflect advanced technology, as alleged by one commenter. The engineering analysis says that "[t]he project will consist of generating equipment in a configuration that has been permitted and is in use throughout the United States and the world." *Engineering Review, Summit Vineyard, LLC, Lake Side Power Plant*, October 25, 2004, (hereinafter, "Lake Side Engineering Review"), at p. 5 (available at: www.airquality.utah.gov/Permits/DOCS/ RN3031001-04.pdf).

Center (CLIEC) were represented as, nor [*sic*] sold as, a Flex Plant™ 30."[209] The Air District also contacted the plant manager from the Lake Side plant, who confirmed that the facility uses the Siemens 501F turbine with the latest FD3 technology, along with a conventional triple-pressure boiler and steam drum; the facility does not use a once-through boiler design.[210]

The commenters' confusion over whether the Lake Side and Caithness facilities use Flex-Plant 30 technology may have arisen because they both use an auxiliary boiler to keep the equipment warm during cold weather.[211] The use of such an auxiliary boiler is common in colder regions where low temperatures can greatly prolong startups during cold weather, but such equipment does not constitute Flex-Plant™ 30 integrated plant design or similar "once-through" Benson boiler design. These two facilities do not, therefore, contradict the District's conclusion that Flex-Plant 30 technology is not yet available.

Regardless of this distinction in the types of technology used at Lake Side and Caithness, however, the Air District interprets the commenters' point to be that the Air District should consider whether to require the same type of technology used at those two plants to keep equipment warm and allow it to start up faster. The Air District considered the use of an auxiliary boiler as is used at Lake Side and Caithness, and its analysis is described in detail in subsection C.2. below. As noted below, however, the Air District found that an auxiliary boiler would not be required as a BACT control because the economic impacts in having to install and operate the auxiliary boiler render it inconsistent with BACT, given the relatively small additional emissions reductions it would achieve. The Air District is therefore not requiring an auxiliary boiler as used at Lake Side and Caithness.

The Air District published this additional investigation and analysis in the Additional Statement of Basis and solicited further public comment. During the second comment period it received comments expressing further disagreement that fast-start technology is unavailable for this facility. These comments stated that Siemens Fast-Start technology is being proposed for combined-cycle facilities that are currently under permitting review, such as the Willow Pass Generating Station and the Marsh Landing Generating Station. The Air District reviewed these facilities in response to these further comments, but disagrees that they are comparable. For Willow Pass and Marsh Landing, these applications proposed to use single-pressure steam turbines and in facilities designed for peaking-to-intermediate duty, unlike this facility (as some

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209 Siemens Technology Statement, *supra* note 207. The Air District also received a comment referencing the proposed El Segundo Power Redevelopment project in connection with the Fast-Start discussion. The El Segundo project as currently planned will use a Siemens single-pressure combined-cycle design, not a triple-pressure design as with this project. (*See* Staff Report, El Segundo Power Redevelopment Project, Proceeding 00-AFC-14 (CEC, June 12, 2008), at p. 3-4 ("New Proposed Site Plan"), available at www.energy.ca.gov/2008publications/CEC-700-2008-006/CEC-700-2008-006.PDF.)

210 Telephone conversation between Weyman Lee, BAAQMD Engineer, and John Bowater, Plant Manager, Lake Side Power Plant, April 8, 2008.

211 See, Lake Side Engineering Review, *supra* note 208, at pp. 6-7; Caithness Long Island Energy Center, *Environmental Impact Statement*, June 2005, at 9-35 – 9-36, available at: www.lipower.org/company/powering/caithness.html.

other commenters correctly pointed out).[212] The Air District therefore disagrees that these proposed facilities show that Fast-Start is currently an available control technology for a triple-pressure facility such as this one, and has concluded that it is not required as a BACT technology here.[213]

Comment VIII.C.2. – Use of Single-Pressure "Flex-Plant 10" Technology:

The Air District also received comments citing the Willow Pass and Marsh Landing facilities that are proposing to use Flex-Plant 10 technology and suggesting that the District should consider a Flex-Plant 10 system for this facility. Other comments took the opposite position, however, stating that Flex-Plant 10 technology is not appropriate for this type of facility. These comments stated that a Flex-Plant 10 system is appropriate for peaking-to-intermediate duty operations, whereas the Flex-Plant 30 system is the appropriate technology for intermediate-to-baseload operations. These comments were based on the observation that there is an energy efficiency penalty when using the single-pressure steam boiler system, compared with the more efficient triple-pressure system that will be used here. This situation was a key element of the Air District's analysis that using Fast-Start technology would not be appropriate for this facility

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212 *See Application for Certification, Willow Pass Generating Station*, June 2008, § 1.1 ("The FP10 units will be intermediate load power blocks, expected to operate at a 40 to 50 percent capacity factor…"); § 2.5.2 ("The design of the power plant will provide for operating flexibility (i.e., ability to start up, shut down, turn down, and provide peaking output) so that operations may be readily adapted to changing conditions in the energy and ancillary services markets."), available at: www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/Volume_01/; Application for Certification, Marsh Landing Generation Station, May 2008, § 1.1 ("The FP10 combined-cycle units will be intermediate load power blocks, expected to operate at a 40 to 50 percent capacity factor…"); § 2.5.2.1 ("The design of the power plant will provide for operating flexibility (i.e., ability to start up, shut down, turn down, and provide peaking output) so that operations may be readily adapted to changing conditions in the energy and ancillary services markets."), available at: www.energy.ca.gov/sitingcases/marshlanding/documents/applicant/afc/Volume%20I/. Note that the applicant has submitted an amendment to its application, significantly changing the proposed facility's design – from two Flex-Plant 10 units operated in combined-cycle mode and two simple-cycle units, to four simple-cycle units. *Application for Certification Amendment (08-AFC-03) for Marsh Landing Generating Station, Contra Costa County, California*, September 15, 2009, available at: www.energy.ca.gov/sitingcases/marshlanding/documents/applicant/2009-09-15_Applicants_Amendment_to_the_Application_for_Certification_TN-53293.PDF.

213 The District also received comments stating that the CEC staff recommended Fast-Start in comments on the proposed facility. These comments cited Condition AQ-SC10 in the CEC's license, which allows the use of Fast-Start technology as an alternative to complying with certain other conditions of certification. The comments implied that the CEC considers Fast-Start technology to be available and appropriate for this facility. The Air District disagrees with these comments. As the District has explained, Fast-Start technology is not currently available for this type of facility, and the CEC has not provided any information to the contrary. With respect to Condition AQ-SC10, although that condition allows the facility to use Fast-Start technology, it does not require it and does not suggest that it is in fact currently available for this facility.

because of the energy efficiency penalty associated with using a single-pressure steam boiler system.

Some comments objected to the Air District's comparison of single-pressure and triple-pressure steam turbine systems. These comments stated that the District's comparison (summarized in Table 13 of Statement of Basis) was based on the plants operating at full capacity, whereas the facility's operation will include startups and shutdowns, which the comments claimed would change the plant's efficiency level. The comments claimed that Westinghouse 501F turbines can be between 36.5% and 56% efficient, and that the Air District's comparison of this triple-pressure plant with the Flex-Plant 10's stated efficiency of 48% might come out differently if it is made at an efficiency different from the 56% efficiency value the District used.[214]

A related group of comments stated that the District should not reject Flex-Plant 10 technology as inappropriate for this type of facility because they claimed that it is not clear what the facility's duty cycle will be. They stated that the frequency of startups and shutdowns is not known, and so it is not possible to tell whether the startup benefits of the Flex-Plant 10 technology will be outweighed by the energy penalty from using a single-pressure steam turbine instead of a triple-pressure turbine. Some commenters stated that the appropriateness of using a single-pressure system should be based on an analysis of the Power Purchase Agreement for the facility.

Response: The Air District agrees with the comments stating that a triple-pressure system is more appropriate for this type of facility, and disagrees with the comments stating that a Flex-Plant 10 system would be more appropriate here. Flex-Plant 10 is an excellent technology to allow peaking-to-intermediate plants – which have to be able to start up and come on line very quickly – to gain the benefits from using combined-cycle technology (as opposed to less efficient simple-cycle turbines). But it is not appropriate for intermediate-to-baseload facilities where quick startup times are less important because of the energy efficiency penalty associated with using a single-pressure steam turbine. For intermediate-to-baseload facilities, it is preferable to obtain the better overall emissions performance achievable through the use of a triple-pressure system instead of using a less efficient single-pressure system like the Flex-Plant 10. (Note that when Flex-Plant 30 technology becomes available it will allow suitable triple-pressure systems to achieve faster startups as well, but this technology is not yet available for this project.)

With regard to the relative efficiencies of a single-pressure Flex-Plant 10 system compared to a triple-pressure system, Air District reviewed its turbine efficiency information in response to this comment and has concluded that the commenter may be misunderstanding the efficiency ratings for these turbines. The 36.5% efficiency factor cited by the commenter for operation of an F-class turbine would be for operation in a simple cycle facility; that is, using the turbine only and not taking advantage of the waste heat in the turbine exhaust to generate steam for the combined-cycle heat recovery boiler. This facility is a combined-cycle facility that will have a heat

[214] Other comments claimed that that the Air District had identified Flex-Plant 10 technology as feasible but rejected it because of costs of disposing of existing equipment. This assertion is incorrect. The Air District rejected Flex-Plant 10 technology because it is not appropriate for a more-efficient triple-pressure plant such as this one.

recovery boiler to generate steam for additional electrical generation. The steam boiler that is being proposed here is a triple-pressure design that is more efficient than the single-pressure design used in the Flex-Plant 10 system. The Air District published this further explanation and analysis in the Additional Statement of Basis and invited further comment during the second comment period on these turbine efficiency issues. The Air District did not receive any further information or comment during the second comment period to suggest that its analysis is incorrect. The Air District has therefore concluded that requiring the facility to use a Flex-Plant 10 here would not be appropriate and is not required by BACT for this type of facility.

With regard to the comments on the facility's duty cycle, and whether it will actually be used as an intermediate-to-baseload facility where the need for efficiency trumps the need for fast startups, the Air District has considered this situation in detail as explained in Subsection VIII.D. below. As the Air District explains there, all indications show that the facility will be used for intermediate-to-baseload service, and there is no indication that the facility will be used as a peaker plant. The Air District has therefore found no reason to revisit its conclusion that requiring a less-efficient Flex-Plant 10 design would be appropriate here as a BACT requirement. The Air District disagrees that the facility should be designed to use this less efficient system, unless there is some demonstrated need for it such as achieving very short startup times as is required for peaking facilities. The Air District declines to interpret BACT to require this source to be redesigned in this manner, based on all of the information it has reviewed about how the facility will be used. The Air District refers commenters to Responses to Comments II.3. and VIII.D.1. for further discussion of this issue.

Comment VIII.C.3. – Potential For Using "Rapid Response" Technology:

The Air District also received some comments citing the corresponding fast-start system being developed by GE, the "Rapid Response" system. Some of the comments also reference the Oakley Generating Station, a proposed facility for which an application has recently been submitted which is proposing to use a GE Rapid Response system.

Response: The proposed Oakley Generating Station plans to use GE's new Rapid Response combined cycle ("CC") integrated plant system.[215] GE's Rapid Response CC integrated plant system is designed to reduce startup emissions by eliminating many of the "holds" inherent in a conventional combined cycle plant's startup sequence, where the gas turbine is held at low-load for long periods so that the steam cycle equipment can be adequately heated and thereby avoid thermal stress and possible damage that might occur if the turbine were ramped-up to full load as quickly as it could be. The Rapid Response CC plant design accomplishes this through use of a patented, completely integrated plant system (an "Engineered Equipment Package", according to

[215] *See generally* Application for Certification, Contra Costa Generating Station, California Energy Commission, Docket No. 09-AFC-4, June 30, 2009, (hereinafter "Oakley AFC"), at p. 5.1-9 (available at: www.energy.ca.gov/sitingcases/contracosta/documents/applicant/afc/index.php.)

GE), which has been designed to reduce the time it takes to ramp up the gas turbine to full load.[216]

This new technology has only very recently been developed, however, and no Rapid Response CC plant has been constructed or is in operation.[217] Rather, GE is currently offering the Rapid Response CC integrated plant design for shipment to project sites in 2012 and anticipates that the first unit employing this integrated plant design will reach commercial operation in late 2013.[218] (The Oakley Generating Station is currently scheduled for commercial operation in the fourth quarter of 2013.[219]) GE also confirmed that the earliest availability for delivery of the Rapid Response CC/7FA.05 system would be late 2012.[220] This delivery timeline calls into question whether the system would be available for use at the Russell City Energy Center and therefore whether it should be considered at part of the BACT analysis. The applicant plans to commence construction at Russell City by September 2010 and anticipates a 30 to 33 month construction schedule that provides for delivery of the equipment to the site seventeen to nineteen months prior to commercial operation.[221] To keep on schedule, all major equipment is scheduled for delivery prior to the end of 2011.[222] Thus, acquiring the integrated Rapid Response CC system could involve substantial delay in the applicant's construction schedule, which calls into question whether this technology should be considered commercially available.[223]

Nevertheless, to be as conservative as possible, the Air District has considered the Rapid Response CC system to be available for this project and has evaluated it along with the other alternatives it looked at in the BACT analysis for startups. The Air District believes that the technology will likely achieve reduced startup emissions, although the exact extent of the improvement over current technology is difficult to quantify at this stage. As no facility has to date been equipped with the Rapid Response CC system, no facility has had an opportunity to demonstrate actual startup emissions performance. Moreover, the performance of existing combined-cycle facilities indicates significant variability in emissions between startup events, making it difficult to predict exactly what level of emissions this new technology will be able to achieve. And the experience of other projects representing "first-of-its-kind" combined cycle

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216 PowerPoint presentation, *GE Energy: Rapid Response Combined Cycle*, Gorden R. Smith (GE Power Plant Systems/Power Plant Engineering), Andrew Baxter (F-Technology Product Manager), September 24, 2007 (hereinafter, "Rapid Response PowerPoint").
217 *See* Letter from Peter J. Bukunt, Account Executive, GE Energy Infrastructure, to Richard Thomas, Vice President, Calpine, re: GE207FA.05 Rapid Response Combined Cycle Plant, January 4, 2010 (hereinafter, "GE Letter"), at p. 1 ("In my email to you of March 13, 2009, I mentioned that, as of that date, no facility using GE's patented Rapid Response Combined Cycle (CC) plant design had been constructed or was in operation. This remains the case…").
218 *Id.* ("we do not anticipate commercial operation of the first unit until the late 2013 time").
219 Oakley AFC, *supra* note 215, at p. 2-32, Table 2.2-1.
220 GE letter, *supra* note 217, at 1 ("the earliest availability for delivery of the Rapid Response CC/7FA.05 system, if an order were placed at this time, would likely be late 2012").
221 Schedule No. SCH-001, revision no. F, January 10, 2010, prepared by Bechtel, Frederick, Maryland, "Russell City, California, USA (2x2x1)- Combined Cycle," job no. 25483-001.
222 *Id*.
223 In the context of the formal five-step Top-Down BACT Analysis, the technology would be eliminated at step two of the analysis if it is not yet commercially available for the project.

plants indicates that initial predictions of startup emissions are often inaccurate. For example, Inland Empire Energy Center ("IEEC") recently requested an amendment of its California Energy Commission license to increase permitted emissions during startup events due to the facility's failure to meet the existing limits.[224] IEEC, which is a demonstration project for GE's first 60-Hz H-class turbines, commenced commercial operation of one of its units on June 29, 2009. (The second unit was damaged during commissioning and is not expected to begin operating until early 2010.) The requested amendment in IEEC's license would increase the permitted CO emissions during startups/shutdowns from 95 lbs/hr to 800 lbs/hr and from 300 lbs/event to 2,000 lbs/event – more than 8- and 6-fold increases, respectively. Increases in startup emissions of this magnitude, if applied to GE's estimated emissions for the Rapid Response CC plant and 7FA.05 Advanced Gas Turbines, would in some cases exceed the BACT limits being established for Russell City. As reported by the Energy Commission's notice concerning IEEC's requested amendment, "the gas turbine startup/shutdown emission limits . . . were based on the best information available at the time that the permit was issued."[225] Indeed, sometimes even the best available information may not be a reliable indicator of actual emissions performance for technologies that have not previously been demonstrated. The Air District has therefore concluded that it would be difficult to assess exactly what level of emissions performance this new technology can achieve at this stage, although it appears that there would be an improvement over best work practices, the BACT technology choice that the Air District proposed at the draft permit stage and evaluated in the Statement of Basis and Additional Statement of Basis. Rapid Response would therefore be ranked as the top technology at Step 3 of the BACT analysis, ahead of best work practices.

The Air District therefore proceeded to Step 4 of the BACT analysis to determine whether there would be any ancillary energy, environmental or economic impacts that would counsel against choosing Rapid Response as the BACT technology choice. The Air District conducted a cost-effectiveness analysis and found that the costs associated with this new technology would be far greater than what can be justified under BACT relative to the emissions reduction benefits that would be gained. According to GE, implementing a Rapid Response CC system at Russell City would cost $275-299 million.[226] To be conservative, the Air District used the lower-bound of this estimate – $275 million – in its analysis. The Air District also did not include the cost for certain elements of the integrated plant design that must be obtained from other vendors,[227] but over which GE retains approval authority due to their impact on overall plant performance.[228]

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[224] *See* Notice of Receipt, Petition to Amend the Energy Commission Decision for the Inland Empire Energy Center Project (01-AFC-17C), December 14, 2009, Docket Log No. 54461; available at: www.energy.ca.gov/sitingcases/inlandempire/compliance/2009-12-14_Notice_of_Receipt_Regarding_Petition_to_Amend_CEC_Decision_TN-54461.PDF.
[225] *Id*.
[226] GE Letter, *supra* note 217, at p. 3
[227] *Id*.
[228] Rapid Response PowerPoint, *supra* note 216, slide 12 (indicating "GE approval of items impacting plant operability", including "Aux boiler to GE spec"). Note, however, that the Air District has separately evaluated the discrete reductions that would be achievable through use of an auxiliary boiler.

By contrast, the estimated cost for the facility as proposed is approximately $164 million.[229] The additional cost for using GE's Rapid Response CC is therefore conservatively calculated at $111 million, which equates to $18,623,100 per year on an annualized basis when taxes, insurance and other administrative overhead costs are included.[230] The Air District then compared this cost with the emission reduction benefits to be gained. As noted above, it is difficult to determine exactly what emissions performance can be achieved from this equipment given that no such systems are in operation and there is no actual operating data to evaluate. The Air District nevertheless evaluated several sources of information on the Rapid Response CC emissions performance and used the most conservative of them. GE's technical specifications for the 7FA turbine using Rapid Response CC provide estimated startup rates of 32 and 162 lbs NO_x and CO, respectively (indicated as "[p]rovided as estimates only").[231] The application for the Oakley Generating Station project is more aggressive, with hot/warm startup NO_x and CO emissions estimated at 22 and 138 lbs, respectively (with 96 lbs. NOx and 540 lbs. CO, respectively, for cold startups).[232] The Air District used the estimates from the Oakley application to be more conservative. Applying these startup emission rates to the Russell City facility's 6x16 operating profile, the Air District concluded that GE's Rapid Response system could achieve as much as 14.8 tons of NOx reductions and 201.4 tons of CO reductions per year.[233] Comparing these potential reductions to the $18,623,100 annualized cost of the Rapid Response CC system, the cost effectiveness calculation comes out to $1.26 million per ton of NOx reductions achieved and $92,468 per ton of CO reductions achieved. These costs are well above what has been required at other facilities to achieve NOx and CO reductions.[234] The Air District has therefore concluded that Rapid Response should not be required here as BACT because of the economic and cost impacts it would have on the project.

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[229] Email from Alex Prusi (Director of Engineering, Calpine) to Barbara McBride (Director, Environmental, Health & Safety, Calpine), December 28, 2009.

[230] *See* spreadsheet, "Cost-Effectiveness Analysis of Requiring Use of GE Rapid Response CC Plant Design for RCEC".

[231] The New 7FA – Technical Specifications", GE Energy (hereinafter "GE technical specifications"), available at: www.ge-7fa.com/businesses/ge-7fa/en/7FA-tech-specs.html.

[232] Oakley AFC, *supra* note 215, at 5.1-9, Table 5.1-6, "Rapid Response Startup and Shutdown Emissions Per Turbine", citing "Source: Radback-CCGS Team, 2009". Note that the Oakley application is still being processed and the proposed limits set forth in the application have not been determined to represent BACT at this stage. Moreover, the applicant has indicated that it may be revising its estimates upwards for purposes of establishing a not-to-exceed BACT permit limit that can be achieved at all times.

[233] *See* spreadsheet entitled "Russell City Energy Center, Comparison of Emissions Reductions Resulting from Rapid Response CC System Assuming RCEC Operating Profile".

[234] The CO cost-effectiveness threshold for purposes of the BACT analysis is discussed above in Section V. For NOx, the Air District has a BACT cost-effectiveness threshold of $17,500 per ton. (*See* BAAQMD BACT Workbook, Policy & Implementation Procedure, available at http://hank.baaqmd.gov/pmt/bactworkbook/intro3.htm.) For both of these pollutants, the costs associated with Rapid Response would be well above what any other permitting agency the Air District is aware of has ever required under BACT. EPA Region 4's National Combustion Turbine List, cited above in footnote 154, provides further evidence to support this conclusion.

2. Auxiliary Boiler Systems

Comment VIII.C.4. – Potential for Using Auxiliary Boiler To Reduce Startup Emissions:
As noted above in connection with the comments discussing the Lake Side and Caithness facilities, which use an auxiliary boiler, several comments raised the issue of whether the Air District should require an auxiliary boiler to be used to keep the HRSG and/or steam boiler warm while it is shut down, which would allow for reduced emissions on startup. Some comments stated that an auxiliary boiler would effect an overall reduction in emissions because any additional emissions from use of the auxiliary boiler would be *de minimis* compared to the startup emissions reductions that would be achieved. Other comments questioned a statement by Calpine in a memo submitted to the District that there is no room at the proposed project site for an auxiliary boiler. Some comments also stated that the CEC had opined that an auxiliary boiler would reduce startup times.

Response: In response to these comments, the Air District considered whether it should require an auxiliary boiler to be used on this project. The District analyzed the startup emissions benefits of using an auxiliary boiler here in the context of the additional costs that would be involved. The District compared startup data from Calpine's facility in Mankato, Minnesota, a facility that is equipped with an auxiliary boiler. For some startups the plant uses the auxiliary boiler and for others it does not, and so the plant allows a direct comparison of the actual emissions reduction impact from using this technology. The data show that using the auxiliary boiler will reduce fuel usage (and consequently emissions) by approximately 18% for warm startups and approximately 31% for cold startups (with no impact on hot startups, as the HRSG and steam turbine are already at a high temperature).[235] Assuming an annual operating profile containing 6 cold startups and 100 warm startups (a conservative estimate because actual startups will likely be lower), a similar reduction at Russell City from using an auxiliary boiler would result in 0.9 tons of NOx and 12.4 tons of CO per year.[236] The Air District compared these potential emissions reductions to the costs of using an auxiliary boiler, based on a cost estimate provided by Calpine and reviewed by the District.[237] That cost estimate showed that the annualized cost would be $1,029,521 for the installation and operation of the auxiliary boiler. In terms of dollars-per-ton, these figures yield a cost-effectiveness number of $1,143,912 per ton for the NOx reductions and $82,800 per ton for the CO reductions. In light of these cost-effectiveness numbers, the costs of requiring an auxiliary boiler here would greatly exceed what any permitting agency would require in order to achieve this level of additional emissions reductions. (*See generally* Additional Statement of Basis at pp. 69-70.)

The Air District published this further analysis of the potential for using an auxiliary boiler in the Additional Statement of Basis and received a number of further comments on the issue. First, some comments provided vendor information that they claimed was used in developing the

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[235] *See* Excel spread-sheet entitled "Aux Boiler start profile DJ.xls".
[236] *See id*. Note that these reductions are net of the small additional emissions that would be generated by the auxiliary boiler itself. The Air District agrees with the commenters who stated that the emissions reductions from the auxiliary boiler would be more than offset by the startup reductions.
[237] *See* Excel spread-sheet entitled "Aux Boiler-NOx-2.xls".

Caithness permit conditions, which they claimed showed the emissions reductions that would be achieved from using an auxiliary boiler. These comments implied that this information provides a better measure of the benefits from using the auxiliary boiler than the information the District used. The comments offered an alternative calculation based on the emission reduction numbers from the Caithness vendor data, which they claimed show that using an auxiliary boiler could eliminate 89.9 tons per year of CO based on the Air District's assumptions regarding the facility's operating profile. Using this larger emissions reduction number, the comments stated that the cost-effectiveness should be calculated at $11,515 per ton of CO reduced, which is approximately 8 times smaller than the number the Air District calculated. The comments claims that at this lower cost level, an auxiliary boiler should be required as BACT.

The Air District reviewed the vendor estimates cited in these comments and disagrees that they support an estimated reduction of 89.9 tons per year of CO from using an auxiliary boiler. The vendor's documents show that the estimated cold startup emissions at 51ºF are 2,164 pounds of CO without the auxiliary boiler and 1,271 pounds with the auxiliary boiler, a difference of 893 pounds. For warm startups, the documents show emissions of 2,157 pounds of CO without the auxiliary boiler and 1,237 pounds with the auxiliary boiler, a difference of 920 pounds.[238] Using these estimates, the annual emissions reductions come to 48.7 tons of CO, not the 89.9 tons calculated by the commenters. This amount of emission reductions would lead to a cost-effectiveness calculation of $21,140 per ton of CO reduced, not the $11,515 figure cited in the comments.

But even taking the numbers presented in these comments at face value, an auxiliary boiler would not be considered sufficiently cost-effective to require as BACT. Even $11,515 is well above the costs of achieving a ton of CO reductions that the Air District found to be justified in its cost-effectiveness analysis in Response to Comment V.1. above. The Air District therefore disagrees with these comments that it should require an auxiliary boiler here to achieve additional startup reductions.

Second, the comments questioned the annual startup profile that the District used, suggesting that there may in fact be more startups per year than the 6 cold and 100 warm startups that the District assumed in its analysis because there are no permit limits on the number of startups per year. With more startups, these comments stated, the cost-effectiveness of using an auxiliary boiler would improve. The Air District disagrees with these comments. The operating profile the Air District used in its analysis is typical of normal operations of a "6x16" intermediate-to-baseload facility such as this one, and there is no indication that its operation will be significantly

[238] *See* Siemens Westinghouse Power Corporation, *Caithness – Bellport Energy Center – Total Estimated Startup and Shutdown Emissions* (December 14, 2004), attached with letter from Jewell J. Hargleroad, Esq., to Weyman Lee, September 16, 2009. Note also that the commenters appear to be unfairly comparing the *average* emissions performance estimated by the vendor when using an auxiliary boiler with the *maximum* not-to-exceed emissions limit for Russell City without an auxiliary boiler. But the basis for their comparison is not entirely clear because the emissions numbers they cite are not found anywhere in the documentation they attached with their comments.

different.[239] And even so, this number of startups is well below the number of warm and cold startups at which an auxiliary boiler would be required for purposes of a BACT emissions control technology.[240] Even if the Air District's assumptions about the facility's operating profile were off by a factor of two or more – a highly unrealistic scenario – the Air District's analysis would still show that an auxiliary boiler is not sufficiently cost-effective here. For all of these reasons, the Air District is not requiring the facility to use an auxiliary boiler here as a BACT technology for startups.

3. Low-Load "Turn-Down" Technology

Low-load "turn-down" technologies are products that allow better performance operation at lower than full load. As outlined above, the Air District has based its BACT limits on the emissions performance seen from the one facility that has installed a "turn-down" product designed to target startup emissions (as opposed to addressing other situations where a turbine might experience low loads), the Palomar facility in Escondido, CA. In this section, the Air District responds specifically to the comments it has received regarding "turn-down" technology as a BACT technology choice.

Comment VIII.C.5. – Use of Op-Flex Low-Load "Turn-Down" Technology:
A number of comments objected to the District's determination not to require Op-Flex low-load "turn-down" technology as a BACT technology for reducing startup emissions. These comments noted that the Palomar facility in Escondido discussed above uses Op-Flex technology, and claimed that this fact demonstrates that the technology is technically feasible for reducing startup emissions. The comments also noted that CEC staff suggested that it should be required as BACT in a comment letter. Some comments claimed that if the Air District does not require Op-Flex technology to be used, as an alternative it should require the same level of startup emissions reductions as achieved by other facilities with Op-Flex.

Response: The Air District reviewed its assessment of Op-Flex in light of these comments. The Air District notes at the outset that the Federal PSD BACT requirement is ultimately an emissions limit, not a control technology *per se* (although, obviously, it must be based on the performance of the best available technology taking into account all relevant factors).[241] Based on the data that the Air District has reviewed from the Palomar facility that uses Op-Flex and early ammonia injection, the District has concluded that the Russell City facility will have

[239] Some commenters have suggested that this facility will actually be operated as a "peaker" plant, but as addressed in detail in response to Comment No. VII.D.1., there is no evidence to support these claims.
[240] Even taking the best cost-effectiveness number asserted in the comments ($11,515 per ton), doubling the number of startups per year would improve the cost-effectiveness only to $5,758 per ton, which is still well above the level at which BACT would require this technology to be used. Using other less optimistic calculations of cost-effectiveness, this point becomes even more striking.
[241] *See, e.g.*, *In re Three Mountain Power*, 10 E.A.D. 39, 54-55 (EAB 2001) (BACT is an emission limitation not a control technology, and if two alternatives can achieve the same emissions performance the choice is essentially immaterial).

startup emissions that are the same as or lower than startup emissions achieved at Palomar. (*See* discussion in Response to Comment VIII.B.1., above.) The Air District therefore agrees with the comments stating that it should require the same level of startup emissions reductions achieved at facilities that have installed Op-Flex. The Air District disagrees, however, with the commenters who claimed that the Air District should specifically require the use of Op-Flex as a technology.

Moreover, the Air District does not find any reason to alter its BACT analysis of Op-Flex as not yet "available" for BACT purposes as an effective technology for reducing startup emissions. The Air District's conclusion was based upon the lack of a manufacturer's guarantee[242]; the limited nature of the data from the only facility using Op-Flex, which is not sufficient to allow a determination that Op-Flex really is achieving any significant reductions in emissions beyond what is already achievable using other approaches; and the fact that no other permitting agencies have ever found Op-Flex to be an achievable technology for reducing startup emissions for purposes of a BACT analysis. None of the comments provided any reason to reconsider any of these rationales. Some comments objected to the District's observation that without a manufacturer's guarantee the District cannot be certain that OpFlex will be able to achieve any particular level of emission reductions, and claimed that the District should use operational data as an alternative. These comments further stated that the data from Palomar provide a precise assessment of exactly what emissions reductions can be achieved from using OpFlex, and show that low-load turndown technologies are technologically feasible to reduce startup emissions. The Air District disagrees with these characterizations of the information from Palomar. The data is limited and preliminary at best, and it provides no firm indication of what reductions may have come from the use of Op-Flex, what reductions may have resulted from starting to inject ammonia earlier during the startup process, and what reductions may have come from other changes such as improved work practices. The Air District therefore continues to conclude that Op-Flex as not yet an available technology, and is appropriately eliminated in Step 2 of the Top-Down BACT analysis. But in any event, based on the additional analysis referred to above, even if the Air District were to address Op-Flex as an available technology in Step 3 of the Top-Down analysis, there is no indication based on the available data that it should be ranked higher than the alternative the District ultimately selected, best work practices. For all of these reasons, the Air District disagrees that Op-Flex should be required as a condition in the permit for this facility.[243]

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[242] Some commenters questioned whether the District should have undertaken further investigation into GE's claims that it will not guarantee startup emissions performance for turbines using its OpFlex system because startup emissions are highly variable and depend on specific plant equipment and configuration. But the manufacturer has informed the Air District that it will not do so, as explained in the Statement of Basis, and the comments have not provided any reason (beyond mere speculation) to the contrary.

[243] Comments also stated that the CEC found that Calpine rejected OpFlex because of the associated cost, and stated in this context that the District needs to ensure that its BACT analysis is untainted by considerations of things like costs. The District disagrees that cost was a part of the District's analysis of Op-Flex technology. The commenter has not identified any element of the Air District's BACT analysis regarding Op-Flex that is based on cost, and the District has not found any either. The Air District published this further explanation in the Additional Statement of Basis (p. 72, fn 131) for further comment during the second comment period, but did not

Comment VIII.C.6. – OpFlex Comments in EPA Region IX Colusa Permit Proceeding:

The Air District also received comments that disagreed with the District's assertion that EPA Region IX does not require OpFlex as BACT, based on the permit Region IX issued for the Colusa Project. The comments noted that a commenter in the Colusa proceeding brought the issue to the Region's attention in a comment, but that the comment was withdrawn and so Region IX did not consider it. The comments requested that the District consider the comments that were submitted and subsequently withdrawn in the Colusa proceeding here.

Response: The Air District agrees that EPA Region IX did not formally respond to the withdrawn comments on the record. But once the issue had been brought to EPA's attention in the comments, the agency would not (and legally could not) fail to require OpFlex technology if that technology were BACT. The agency has an independent responsibility to impose BACT based on information brought to its attention in a comment, even if the comment that brought the issue to light is subsequently withdrawn. For this reason, the District stated in the initial Statement of Basis that EPA Region IX did not require OpFlex as BACT.[244]

Moreover, although the Air District pointed out that EPA had not required the use of OpFlex as BACT at Colusa, the Air District conducted its own case-by-case evaluation and reached its own independent conclusion that BACT does not require that OpFlex technology must be used here as a condition of the permit (although as noted above the Air District has found that the permit limits it is imposing are as stringent as the emissions performance that has been achieved at the one facility using an OpFlex product for startups). That analysis, as further considered the Additional Statement of Basis and in this Response to Comments document, provides a sufficient basis for the current permitting action regardless of EPA Region IX's analysis. The District continues to believe that EPA Region IX's conclusions lend further credence and support to its analysis, however.

Finally, as for considering the Colusa comments that were withdrawn, the Air District obtained a copy of the comments from EPA Region IX to ensure that it had researched all information that could have bearing on this issue, and found nothing whatsoever in those comments to suggest that OpFlex should be required here. The comment letter cited several of the same points about

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receive any further comment pointing to any area in the District's analysis where Op-Flex technology was rejected based on costs.

[244] The same commenter also suggested that U.S. EPA Region 9's decision (or lack thereof) not to require OpFlex™ in the PSD permitting decision for Colusa Generating Station was irrelevant to the Air District's decision because the proposed Russell City Energy Center would be located in a populated metropolitan area designated as nonattainment for certain National Ambient Air Quality Standards. The Air District notes that the suggestion implicit in this comment – that the BACT standard should apply differently between a location in a "major metropolitan area" and one outside such an area – is without any basis in the federal PSD regulations. Further, to the extent that the commenter intended to suggest that PSD permits should not be issued or the BACT standard should be applied differently for sources located in non-attainment areas, the Air District notes that such sources are subject to non-attainment New Source Review for non-attainment pollutants.

the Palomar Energy Center that have been raised in this proceeding, to which the Air District is responding in detail in this section.

The Air District published this further explanation of its view of the Colusa permit proceeding in the Additional Statement of Basis and solicited further public comment on this issue. The commenters who suggested that the Air District consider the Colusa comments submitted further comments during the second comment period stating that the Air District had not adequately analyzed them. These further commenters did not explain any area in which the Air Districts' response was not adequate, however. The comments also claimed that the Colusa permit has been reopened for modification, although they did not explain how that would impact the Russell City permit. The Air District disagrees that there is anything in these further comments to alter the permitting analysis on these issues. EPA is currently reopening the Colusa permit to make minor amendments, but these proposed amendments do not involve the startup limits and would not require the facility to install an OpFlex system.[245]

Comment VIII.C.7. – Availability of Siemens Low-Load Turn-Down Product:

Another comment claimed that, based upon telephone conversations with Siemens representatives, a low-load "turn-down" technology product is currently available for Siemens turbines.

Response: The Air District investigated this issue further and reviewed communications from Siemens confirming in writing that it does not have a low-load product that is commercially available for F-class turbines. Siemens' low-load product, known as "Low Load Carbon Monoxide" (LLCO), has been validated for G-class turbines as noted in the documentation the Air District relied on in the initial Statement of Basis. (*See* Statement of Basis at p. 41 and n. 33.) The Air District confirmed this with Siemens in response to this comment. Siemens reports that "LLCO validation for F-class turbine began in December 2008 and [is] currently in process [but] the validation for the F-class turbine has not been concluded."[246] The Air District published this further explanation and analysis in the Additional Statement of Basis and received no further comments on this issue.

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[245] *See* Proposed Amended Permit Conditions, Colusa Generating Station, PSD Permit No. SAC 06-01, available at www.regulations.gov/search/Regs/home.html#documentDetail?R=0900006480a1ee9e (redline version showing proposed changes).

[246] *See* Siemens Technology Statement, *supra* note 207. Further, for the reasons discussed in the section of this document on the Air District's BACT analysis for greenhouse gas emissions (Section III), the Air District has found that use of G-class turbines in place of the Applicant's proposed F-class turbines does not constitute BACT for Russell City Energy Center. Rather, as discussed in that section, use of G-class turbines for a proposed nominal 600 MW combined-cycle power plant would require installation of a substantially smaller steam turbine, which would result in a significant reduction in the plant's overall efficiency rating. In light of the ancillary environmental and energy impacts that would result from this efficiency loss, the Air District in not requiring the use of G-class turbines as BACT for this project.

4. Miscellaneous BACT Technology Choice Issues

Comment VIII.C.8. – Use of "Best Work Practices" As BACT for Startups:
Some comments objected to the selection of Best Work Practices as the BACT control technique, characterizing this approach as simply following 'operating instructions'.

Response: Optimizing a facility's operating procedures to implement best work practices is an effective and well-accepted method of minimizing emissions from startups and shutdowns.[247] Moreover, as described in more detail in these Responses to Comments, and in the Statement of Basis documents that the Air District has published previously, the use of best work practices this case will allow the facility to comply with the BACT emissions limits that the Air District is imposing in the final permit. The Air District does not find that commenter's characterization of this approach to minimizing emissions provides any reason to alter its BACT analysis. The Air District published this further justification and analysis in the Additional Statement of Basis, but did not receive any further comments.

Comment VIII.C.9. – Future Consideration of Emerging Startup Technologies:
Some comments questioned whether the District will be monitoring improvements in startup technologies for future modification of the permit for this facility, or for use in future permits.

Response: The District will be monitoring improvements in power plant startup technologies for all power plant permits it issues, both for new facilities and for modifications to existing facilities including the Russell City facility. If the applicant seeks a significant permit modification in the future that requires an upgrade of BACT technology, the District will require the state-of-the-art technology available at that time. The BACT requirement imposes an obligation on permitting agencies to review technological improvements and to impose emissions limits based on the state of the art at the time of permitting, which is what the Air District has done here as explained in the BACT analyses and justifications it has provided in this proceeding.

Comment VIII.C.10. – Use of Solar Technology to Reduce Startup Emissions:
The Air District also received comments stating that the CEC had opined that the use of a solar array could reduce startup times, and otherwise suggesting that a hybrid solar facility would be appropriate to control startup emissions.

Response: The Air District considered the potential for incorporating a hybrid solar design and other solar technologies above in Section II regarding the currentness of the generating technology for this plant and in Section III regarding greenhouse gas BACT and energy

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[247] *See, e.g.*, Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, U.S. EPA Region I (Jan. 28, 1993); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Feb. 15, 1983); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Sept. 28, 1982).

efficiency. As addressed in those sections, even if solar alternatives could be made a part of the BACT analysis without impermissibly redefining this source, solar technologies would not be an available alternative here given the space constraints and other limitations associated with this project. For the same reasons why solar technologies would not be appropriate BACT alternatives discussed in response to those comments, the Air District disagrees that solar technologies would not be appropriate BACT alternatives with respect to reducing startup emissions.

D. Frequency of Startups And Implications For BACT Analysis

<u>Comment VIII.D.1. – Number and Frequency of Startups/Shutdowns:</u>
The Air District also received comments expressing a concern that the facility may have frequent startups and shutdowns. These comments noted that the Air District is permitting this facility as an intermediate-to-baseload facility, but stated that the facility could be used in a "peaking" mode, meaning it would remain idle most of the time but could be started up and shut down frequently to respond to short-term changes in demand. Some comments inferred from the proposed daily emissions limits and from CEC documentation that normal operation could include one or two hot startups per day.[248] The comments stated that the District needs to establish a credible scenario of likely startup and shutdown events, and base its permitting analysis on that scenario. Some comments stated that the District should base its analysis of the facility's operating profile on what is provided in the facility's power purchase agreement. In particular, some comments objected to the Air District's elimination of Flex-Plant 10 technology in the BACT technology analysis based on concerns about the facility's operating profile. As noted above in Response to Comment VIII.C.2., these comments stated that the Air District should not rule out requiring Flex-Plant 10 technology, which offers reduced startup emissions but at the expense of energy efficiency and overall emissions performance, unless the Air District can establish with more certainty that the facility will in fact be used in an intermediate-to-baseload capacity. Other comments expressed similar concerns about the operating profile the Air District used in determining that an auxiliary boiler would not be sufficiently cost-effective in reducing startup emissions. As noted above in Response to Comment VIII.C.4., these comments stated that if the facility was operated in a peaking mode and had more frequent

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[248] Some comments noted that the Russell City facility is expected to be a fast-ramping flexible combined cycle project, and that according to PG&E, Russell City will have operational flexibility that will help PG&E integrate intermittent renewable resources into PG&E's portfolio. These comments implied that the facility may not remain in use all the time, but may shut down to allow renewable resources to be used when they are available and then start up again to fill in gaps when the sun is not shining or the wind is not blowing, for example. Although renewable portfolio goals are not directly related to any PSD permitting requirements, to the extent that this facility can help transition California to a renewable power generation portfolio, the Air District agrees that this is a worthy goal. To the extent that these characterizations are correct, however, the Air District does not consider this attribute of the facility to be inconsistent with the facility's design as an intermediate-to-baseload facility, and the comment has not provided any explanation why it should be considered inconsistent. Intermittent use to help integrate intermittent renewable resources is not inconsistent with intermediate-to-baseload operation.

startups than the Air District assumed in its analysis, an auxiliary boiler might be sufficiently cost-effective to warrant requiring it here as BACT.

Based on these concerns, some of the comments stated that the Air District should impose limits on the number of startups and shutdowns for the facility to ensure that it is not used as a peaking facility. Some comments also objected to having startup and shutdown emissions subject to the annual emissions limit in the permit, on the grounds that an annual cap will allow the facility to over-control steady-state emissions to allow higher startup and shutdown emissions. These comments stated that startup and shutdown emissions will contribute to short-term air quality impacts, which are not addressed by an annual limit.

Response: The Air District has reviewed the facility as proposed and has not found any indication that it is not in fact being built for intermediate-to-baseload operation. To the contrary, all available information suggests that it will be used for intermediate-to-baseload operation.

One clear indication is that the facility has been designed and proposed to maximize energy efficiency, which is being prioritized over fast start times. This tradeoff between a low heat rate (an indication of energy efficiency) and quicker startups times is what determines how power plants are dispatched – that is, whether they are kept on-line or whether they are turned off when demand is not at its peak. Whether and when plants are turned on to provide power to the grid is determined by the California Independent System Operator ("ISO"), which ensures that the state's electricity grid operates reliably at all times. A particular plant's position in the "dispatch order" is determined primarily by how efficiently it can generate electricity, along with how long it will take for the plant to start up to meet the grid's needs in the short term. The ISO keeps the plants with the lowest heat rate (highest energy efficiency) online the longest, as when demand falls it obviously makes the most sense to shut down the higher heat rate (lower efficiency) facilities first. Those that the ISO dispatches only to respond to short-term spikes of the highest demand, by contrast, are those with short startup times that can come on-line quickly in times of immediate need; in those situations, higher heat-rate (lower efficiency) facilities can be used because they do not need to operate as long and so the higher costs and emissions from having to burn more fuel per megawatt of power generated are not as much of a concern. For these reasons, it is a fundamental truth about way in which power plants are dispatched that highly efficient plants with low heat rates such as this one will be used primarily for baseload and intermediate service, and not for peaking service where the less efficient, higher-heat-rate facilities are dispatched to meet short-term peak periods of high demand. The Air District therefore disagrees based on the design of the facility that this facility will be used as a peaker plant, as the comments suggested.

The Air District also disagrees that this facility will be used as a peaker plant based on its review of available information from the record of proceedings before other California regulatory agencies. The information the Air District discovered strongly supports the conclusion that this facility will be an intermediate-to-baseload facility. For example, the California Public Utilities Commission ("CPUC") has expressly made a finding that the facility is subject to California's CO_2 Emissions Performance Standard ("EPS"), which applies only to "baseload generation facilities designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent."[249] Similarly, in related regulatory proceedings concerning the approval of a natural gas pipeline project, PG&E described the Russell City facility and two other highly efficient facilities as having "the lowest heat rates of all the units in PG&E's portfolio" and therefore requiring "the most steady demand" for natural gas supply to meet the needs of PG&E's customers, further suggesting that these facilities – including Russell City – will be dispatched in an intermediate-to-baseload capacity.[250] PG&E's testimony further supports the CPUC's classification of the proposed facility as a "baseload generating" facility with an assumed 60% or greater capacity factor, and thus the Air District's conclusion that this facility will not be used as a peaker plant.[251]

Finally, the Air District also reviewed the Power Purchase Agreement for this facility for indications of how the facility will be dispatched, as some of the comments suggested. The Power Purchase Agreement requires that the facility be available for dispatch on a "6 x 16" basis, meaning that it has to be available to operate at least 16 hours a day, 6 days a week.[252] This dispatch requirement is typical for an intermediate-to-baseload facility, and is not the type of dispatch requirement that would be seen in a Power Purchase Agreement for a peaker plant. This is also the operating scenario on which Calpine has agreed to provide NOx offsets for the facility. It is unlikely that Calpine would provide NOx offsets to accommodate this level of operation if the facility were actually intended to be operated as a peaker with far fewer total hours of operation per year.

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[249] *See* Decision Approving Settlement Agreement Regarding the Second Amended and Restated Power Purchase Agreement, California Public Utilities Commission, April 16, 2009, Decision 09-04-010, Issued April 20, 2009, Application of Pacific Gas and Electric Company for Expedited Approval of the Amended Power Purchase Agreement for the Russell City Energy, Application 08-09-007 (Filed September 10, 2008) Company Project (U39E), pp. 34-35; available at: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/100001.pdf. ("In January 2007, the Commission adopted the Emissions Performance Standard (EPS), which requires that baseload generation facilities designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent demonstrate that the net emissions rate of each baseload facility underlying a covered procurement is no higher than 1,100 lbs. of carbon dioxide (CO2) per megawatt hour. Based on the definitions provided in the EPS decision, the RCEC contract is a covered procurement.")

[250] Pacific Gas and Electric Company, Request for Approval of Ruby Pipeline Transportation Arrangements, Prepared Testimony, Supplemental Testimony, Electric Fuels Department, Application 07-12-021, U 39 M, February 15, 2008, p. 8; available at: https://www.pge.com/regulation/RubyPipeline/Testimony/PGE/2008/RubyPipeline_Test_PGE_20080215-01.pdf.

[251] Regarding the comments citing the Energy Commission's references to multiple daily startups in its Staff Assessment, this scenario was used to determine the *daily maximum* emissions that could occur on a single day for purposes of setting a not-to-exceed daily emissions limit. Use of this assumption to establish the maximum daily emissions limit does not mean that the Energy Commission believes that the two startups per day will be a common occurrence.

[252] *See* Second Amended and Restated Power Purchase and Sale Agreement between Pacific Gas & Electric Co. and Russell City Energy Co., LLC, Appendix II.

For all of these reasons, the Air District concludes that there is no indication that this facility will be used as a peaker plant with low overall usage but a high number of startups and shutdowns. The Air District therefore disagrees with the comments suggesting that the facility will be operated in this manner.

With respect to requiring the facility to be designed using a single-pressure steam turbine system in order to accommodate Flex-Plant 10 technology, the Air District disagrees that this would be appropriate here or required under a BACT analysis. As noted above in response to Comment VIII.C.2., given the energy penalty associated with switching to the single-pressure design used in the Flex-Plant 10 technology, a Flex-Plant 10 would actually result in greater emissions overall from this facility, even though startup emissions could be reduced. Moreover, a permitting agency cannot require an applicant to redesign its proposed source in this way under the BACT requirement. The triple-pressure system this facility incorporates – with its low heat rate (high efficiency) that will allow it to be used effectively as an intermediate-to-baseload facility – is an inherent design element of the facility and is integral to the facility's fundamental purpose. BACT cannot require an applicant to redesign a source to change this fundamental design element.

With respect to requiring the facility to use an auxiliary boiler, the Air District disagrees that it would be appropriate here given the high cost and relatively low emissions reduction benefit that could be achieved, as noted above in response to Comment No. VIII.C.4. As discussed there, an auxiliary boiler would not be sufficiently cost-effective to be required as a BACT technology. There is no indication from the Air District's review of how this facility will be operated that would alter the Air District's analysis on this issue.

Finally, with regard to whether the Air District should impose a specific numerical limit on the number of startups and shutdowns the facility may have, the Air District disagrees that this would be an appropriate application of the BACT requirement. Power plants need flexibility to be dispatched as determined by the ISO in order to ensure a reliable and efficient electrical grid, and a specific limit on the number of times a facility can start up and shut down over a given period of time would hinder that goal. Moreover, the number of startups and shutdowns are already subject to indirect limits because startup and shutdown emissions are included in the daily and annual limits the facility will be subject to. The Environmental Appeals Board has approved of such an approach as sufficient to satisfy BACT for startup emissions, even in the absence of stringent numerical limits on emissions per startup as the Air District is imposing here.[253] For both of these reasons, the Air District disagrees that a specific numerical limit on the number of startups and shutdowns would be appropriate.

Similarly, the Air District disagrees with the comments that it is inappropriate to include startups in the annual emissions cap. As noted above, the Environmental Appeals Board has supported such an approach as an appropriate means to address startup emissions for purposes of the BACT

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[253] *In re Sumas Energy 2 Generation Facility*, PSD Appeal Nos. 02-10 & 02-11 (Order Remanding in Part and Denying Review in Part), Slip Op. at pp. 19-20 (March 25, 2003); *In re Sumas Energy 2 Generation Facility*, PSD Appeal No. 05-03 (Order Denying Review), Slip Op. at pp. 21-22 (May 27, 2005).

requirement. The Air District also points out that startups will not only be subject to the annual emissions limits, but will also be included in the facility's daily emissions limits, as well as the specific limitations on the emissions per startup outlined above. Even if the facility were to over-control its steady-state emissions such that it has extra room under its annual cap, startup emissions will still be subject to these additional limits. These limits will ensure that short-term emissions impacts are minimized to the greatest extent achievable, consistent with BACT and the protection of ambient air quality. This is not a case of either annual limits or short-term limits, as these comments seem to suggest. Rather, it is a case of multiple emissions limits addressing this issue, which will impose restrictions both on short-term and long-term emissions.

IX. COMMISSIONING PERIOD ISSUES

Comment IX.1. – Length of Commissioning Period:

The Air District also received comments stating that it should require a shorter commissioning period. The comments claimed that the data the District reviewed demonstrates that a shorter time is feasible, citing examples in the data of 96 hours and 207 hours taken to commission certain other turbines.

Response: The Air District disagrees that the data it reviewed show that a shorter commissioning period is feasible. The data show that the time required for commissioning varies greatly from turbine to turbine, and that a reasonable allowance must be made for this variability. The data the Air District evaluated show that although on occasion facilities have been able to complete commissioning in as little as 96 hours, on other occasions they have required as long as 297 hours. Based on this data, as well as the Air District's review of the applicant's estimate of the time that will be required, the Air District concluded that 300 hours is a reasonable time limit. The Air District therefore disagrees with this comment that a shorter time period is feasible as a BACT requirement. The Air District published this further justification and rationale in the Additional Statement of Basis and did not receive any further comment from any member of the public during the second public comment period.

X. SULFURIC ACID MIST ISSUES

Comment X.1. – Sulfuric Acid Mist Emissions and Compliance with PSD Requirements:
The Air District received comments questioning the District's assertion that emissions of sulfuric acid mist are difficult to estimate because the conversion of fuel sulfur to SO_3 and then to H_2SO_4 is not well established. These comments suggested that the District should be in a position to explain more precisely what actual sulfuric acid mist emissions will be. The comments also questioned whether the facility will in fact emit less than the 7 tons-per-year PSD significance threshold. In addition, some comments claimed that the permit should limit sulfuric acid mist emissions to less than 38 pounds per day.

Response: In the initial Statement of Basis and Additional Statement of Basis, Air District explained that it had estimated sulfuric acid mist emissions as accurately as it can, and believes that emissions will be below 7 tons per year. In light of further comments received on this issue, the Air District conducted an additional review of available data on sulfuric acid mist emissions that would be expected from this facility, and has concluded that its initial analysis is sound. The Air District reviewed a recent sulfuric acid mist source test result from a similar power plant that showed an average 8% conversion of fuel sulfur to sulfuric acid mist.[254] Based on that test result, the Air District assumed a 10% conversion factor and assumed a fuel sulfur content of 0.25 grain/100 ft^3, which is the maximum permitted annual sulfur content pursuant to Permit Condition 12. Based on these assumptions, the Air District estimates that sulfuric acid mist emissions will be up to 2.1 ton/year for both power trains, which is well below the 7 ton/year PSD significance threshold level. The Air District is not aware of any other data or analysis suggesting that emissions will be over 7 tons per year, and none of the comments on this issue cited any, and so the Air District continues to believe that this is an accurate assessment.

Moreover, the Air District is not simply relying on this estimate to ensure that emissions will in fact be below 7 tons per year. The permit includes an enforceable sulfuric acid mist limit to ensure that emissions stay below this level, and the facility will be required to conduct compliance testing to ensure that they do. This testing requirement will ensure that actual emissions are below 7 tons per year, regardless of the accuracy of the Air District's estimate.

With respect to the need for a daily 38-pound emissions limit, EPA's Federal PSD permitting requirements regulate sulfuric acid mist on an annual basis and require annual emissions to be below 7 tons per year if a BACT analysis is not conducted. The Federal PSD requirements in 40 C.F.R. section 52.21 do not break that 7 ton/year threshold down into a daily emissions limit. Moreover, even if there was a daily 38-pound limit, the facility would still more likely than not remain below even that daily emissions number given how much of a margin it has below the applicable limit in the annual emissions calculations outlined above. For all of these reasons, the Air District disagrees that the facility will exceed the PSD significance threshold for sulfuric acid mist and concludes that the facility does not trigger PSD regulatory requirements for this pollutant.

[254] Source Test Results, Gateway Generating Station, Jan. 4-14, 2009.

Comment X.2. – Sulfuric Act Mist Compliance Testing:

The Air District also received comments questioning whether annual compliance testing will be adequate to ensure compliance with the 7 tpy permit limit. The comments suggested that the facility might simply retest in the absence of oversight until compliance is demonstrated. The comments suggested that the District establish specific test dates to prevent test manipulation by retesting.

Response: The Air District considered this issue as well, and notes that the permit conditions require all non-compliance to be reported to the Air District. (*See* Permit Condition No. 37.) Thus, any non-compliance discovered during a compliance test will be reported, and the facility will not be allowed to keep a failed test secret and conduct a further test to show compliance. The Air District has therefore concluded that the compliance testing requirements as proposed will not allow the potential for test manipulation by retesting. The Air District published this further justification and analysis in the Additional Statement of Basis and did not receive any further comments from any members of the public on this issue during the subsequent comment period.[255]

Comment X.3. – Information on Sulfuric Acid Mist Testing:

The Air District received comments citing a paper on new methodologies for estimating total sulfuric acid emissions from power plants. The commenters did not explain how this information pertains to this permitting action, however.

Response: The Air District acknowledges receipt of this comment. The Air District is unclear as to why the commenters consider this paper relevant, however, as the comments did not explain how this information pertains to this permitting action. The Air District has reexamined the issue of sulfuric acid testing methodologies, however, to the extent that these comments were intended to question the testing methodologies that will be used to determine compliance with the permit limits. The Air District notes in this regard that any testing methodology must be approved by the Air District. This approval requirement ensures that the Air District can require the most accurate and up-to-date testing methodologies to be used. The Air District therefore acknowledged the information provided by these comments in the Additional Statement of Basis, but explained that there was nothing in the information to suggest that the proposed permit conditions should be changed in some way. The Air District solicited further input on this issue in the Additional Statement of Basis, but did not receive any further comments during the second public comment period.

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[255] The District did receive a letter after the close of the second comment period stating that the sulfuric acid mist limit of 7 tons per year would be unenforceable as a practical matter. The letter based this conclusion on an assertion stated that the standard sulfuric acid mist test methods are not accurate, and may not be able to detect emissions at levels as low at 7 tons per year. This communication was not received during the comment period and is therefore not a formal comment that the Air District is obligated to respond to. The Air District notes, however, that current test methods are detecting sulfuric acid mist at levels below 7 tons per year, as evidence by the Gateway Generating Station test results. (*See id*.)

XI. DIESEL FIREPUMP ISSUES

Comment XI.1. – Restrictions on Diesel Firepump Hours of Use:

The Air District received comments regarding the backup diesel firepump engine stating that there would be no restriction on the engine being used only for emergencies. The comment noted that the proposed permit conditions would allow the firepump engine to be operated for reliability, but contended that this means that the diesel firepump can be used as a backup for the combustion turbines and heat recovery boilers. The comments claimed that the firepump engine's emissions will be uncontrolled as a result of this situation, and stated that the District should reduce the allowable operating time of this engine as much as possible and limit its use to only emergencies.

Response: The Air District disagrees that the permit will allow the firepump to be used for non-emergency purposes (except for short periods as necessary for testing, maintenance, and reliability purposes). The permit conditions explicitly limit operation to emergencies and for these specific, necessary non-emergency purposes, and to an annual total of 50 hours for non-emergency uses. Moreover, it would not be possible to use the diesel firepump engine as a backup for the turbines even if the permit allowed for such a use. The firepump engine is rated at 3400 hp, which is the equivalent of around 2.5 MW. This level of output simply could not serve as a backup for a 200 MW combustion turbine.

Comment XI.2. – Use of Electric Motor For Firepump:

As noted above the discussion of greenhouse gas BACT analysis for the diesel firepump, the Air District received a comment suggesting that the District consider requiring an electric firepump instead of a diesel firepump to reduce emissions.

Response: The Air District incorporates its response from the greenhouse gas BACT analysis. As stated in that response, the facility is required to have both an electric power supply and a diesel power supply because of fire safety requirements established by the NFPA. The Air District therefore disagrees that it could require an electric motor in the BACT analysis. Requiring an electric motor instead of a diesel engine would impermissibly redefine the source, and so it would not even be considered as an available technology in the BACT analysis. Moreover, even if the Air District were required to analyze the use of an electric firepump under the BACT analysis, it would eliminate it at Step 2 in the top-down BACT analysis as not feasible for the fire protection purposes it will be serving at this facility.

XII. MONITORING ISSUES

The Air District also received some comments on the proposed monitoring requirements for the facility. The Air District has conducted further review and analysis of the proposed monitoring requirements, as explained below.

Comment XII.1. – Monthly Sulfur Monitoring:

The Air District received comments claiming that the proposed monthly monitoring of the sulfur content of the facility's natural gas fuel is not frequent enough. The comments claimed that the sulfur content of the natural gas can vary significantly from one quarter to another (citing data tabulations from PG&E's website), and stated that for this reason enhanced monitoring should be required. The comments claimed that the District should require weekly sulfur monitoring in order to ensure accurate monitoring of sulfur content.

Response: The Air District considered this issue further in light of these comments, and has concluded that weekly monitoring is not necessary to ensure compliance with the natural gas sulfur limits. The comments claim that sulfur content can vary from quarter to quarter, but even if this is so, a monthly testing requirement will be able to track such variations. The comment did not point to any evidence that the additional data that could be gained from weekly monitoring would be worth the additional burden of doing so, and the Air District is not aware of any. The Air District published this additional justification and rationale in the Additional Statement of Basis, but did not receive any further comments from any member of the public on this issue during the second comment period.

Comment XII.2. – Use of PG&E Sulfur Data:

The Air District also received comments that criticized its proposal to allow Russell City to use PG&E's monthly gas sulfur content measurements if Russell City can show that they are 'representative'. Some comments claimed that there are no objective criteria specified in the permit conditions as to what qualifies as 'representative'. Some comments also claimed that PG&E adds chemicals to its natural gas and does not assure the accuracy of its published information. The Air District also received comments stating that ASTM fuel sulfur analysis methods were updated to correspond to NSPS Subpart GG as revised July 2004.

Response: The Air District reviewed the proposed requirements for sulfur monitoring in the draft permit in light of these comments, and has concluded that they are adequate to ensure compliance as originally proposed. The sulfur monitoring condition allows the facility to use PG&E data only if the facility can demonstrate that the data is representative. PG&E data will not be acceptable if it is not accurate. Moreover, "representative" has a well-understood meaning and does not need "objective criteria" to define it further. In plain English, this proposed condition would require that the PG&E data provide a true and accurate picture of the actual sulfur content of the natural gas to be acceptable. With respect to the information about the ASTM fuel sulfur analysis methods, the Air District acknowledges the information but does not find anything in the comment suggesting that the permit conditions need to be changed. The condition requires accurate testing of the sulfur content of the natural gas, and the fact that testing standards may have been revised is not inconsistent with this requirement. The Air District published this additional justification and rationale in the Additional Statement of Basis, but did not receive any further comments from any member of the public on this issue during the second comment period.

Comment XII.3. – Parametric Particulate Matter Monitoring:

The Air District also received comments stating that it should require more stringent monitoring for PM emissions. The comments claimed that PM emissions are monitored only using heat input, coupled with an emission factor generated from one annual source test. The comments claimed that this information will not accurately predict the PM emissions resulting from this facility. The comments claimed that PM emissions can increase from poor air/fuel mixing or maintenance problems.

Response: The Air District reviewed this issue as well in light of these comments, and it disagrees that annual compliance testing for particulate matter emissions is inappropriate. A primary factor influencing PM emissions is sulfur content in the natural gas, which will be monitored on a monthly basis. To the extent that poor air/fuel mixing or similar combustion problems (whether related to maintenance problems or otherwise) might also increase PM emissions, those conditions would also be manifested in higher Carbon Monoxide emissions. Carbon Monoxide emissions are monitored on a continuous basis, and so any such combustion problems would be detected and addressed immediately. The Air District does not find that it would be necessary to add more frequent PM monitoring as well to address these concerns. The Air District published this additional justification and rationale in the Additional Statement of Basis, but did not receive any further comments from any member of the public on this issue during the second comment period.

XIII. PSD AIR QUALITY IMPACT ANALYSIS ISSUES

The Air District received a number of comments on its Air Quality Impact Analysis, including its modeling analysis showing that emissions from the Russell City Energy Center will not have any significant contribution to any exceedance of the NAAQS for any PSD pollutants and its soils and vegetation analysis showing no significant adverse impacts to soils and vegetation. Many of the comments were directed towards $PM_{2.5}$ impacts in particular. In response to some of these comments, the Air District conducted additional review and analysis, which it published in the August 2009 Additional Statement of Basis. The Air District then received further comments during the second comment period. The Air District's responses on these issues are presented in this section.

A. Air Quality Impact Modeling and Analysis Issues Generally

The Air District first addresses comments related to the Air Quality Impact Analysis and modeling in general. Comments relating to $PM_{2.5}$ specifically and to the soils and vegetation and other analyses are addressed in subsequent subsections.

Comment XIII.A.1. – Currentness of Air Quality Impact Analysis Methodology:
The Air District received comments questioning whether its use of EPA's 1990 Draft NSR Workshop Manual as guidance for conducting the Air Quality Impact Analysis was appropriate. The comments noted that the NSR Workshop Manual is not a binding regulation, and suggested that it may have been superseded by more recent EPA regulatory enactments.

Response: Although the NSR Workshop Manual is not binding as the comments correctly point out, it provides a useful framework for conducting an Air Quality Impact Analysis and has been approved by EPA for use in PSD permitting analyses. The Air District therefore uses the NSR Workshop Manual as guidance in situations where there is not any other more authoritative binding guidance that has been provided by EPA. The comments did not point out any specific area where the Air District's reliance on the NSR Workshop Manual was improper, and the District is not aware of any. The Air District explained this situation in the Additional Statement of Basis and invited members of the public to identify any specific areas where using the NSR Workshop Manual as guidance is inappropriate during the second comment period. No commenters identified any such areas. (Indeed, several comments pointed out areas of the NSR Workshop Manual that they contended the Air District must follow.) The Air District has therefore concluded that its use of the NSR Workshop Manual as guidance is appropriate.[256]

[256] Comments also cited a new section of 40 C.F.R. 52.21 that EPA proposed in 2007 – a new subsection (f) – that would have clarified how emissions would be calculated for purposes of PSD increment consumption analyses. The Air District is unaware of any such regulatory changes that have become final, and the comment did not identify any. Moreover, the comment did not identify any area in which the Air District's emissions calculations or increment consumption analysis was defective or should have been done differently than it was. The Air District therefore disagrees with these comments to the extent that they imply that the Air District erred in how it applied the NSR Workshop Manual and the PSD requirements in general.

Comment XIII.A.2. – PM_{10} Air Quality Impact Analysis:

The Air District received comments during the first comment period stating that it should use the highest modeled PM_{10} value to compare with the ambient air quality impact significance threshold, not the sixth-highest value as used in the initial Statement of Basis.

Response: EPA's modeling guidelines for PM_{10} specify that the sixth-highest modeled value should be used to compare with the significance threshold.[257] As 40 C.F.R. Part 51 Appendix W states, "[f]or the 24-hour PM-10 NAAQS (which is a probabilistic standard)—when multiple years are modeled, they collectively represent a single period. Thus, if 5 years of [National Weather Service] data are modeled, then the highest sixth highest concentration for the whole period becomes the design value." Furthermore, the EPA guideline model AERMOD is hardcoded with an algorithm using the sixth-highest daily concentration; if another approach is to be used, the guideline approach has to be overridden.[258] For these reasons, the Air District concludes that the best reading of the EPA guidance on this issue is that it requires the sixth-highest modeled value to be used for the PM_{10} analysis.

Nevertheless, in response to this comment the Air District evaluated the potential impacts from using the highest modeled value for the PM_{10} analysis. The Air District found that using the assumption that the cooling tower water could have up to 8,000 ppm (by weight) Total Dissolved Solids (TDS), the highest modeled value would exceed the PM_{10} significant impacts level of 5 $\mu g/m^3$. The Air District therefore explored with the applicant whether it could keep TDS levels within a lower limit. The applicant found that it could keep TDS within a limit of 6,200 ppmw, and so the Air District is lowering the TDS limit in the permit to that level. With the TDS limit reduced to 6,200 ppmw, the cooling tower's PM_{10} emissions would be reduced accordingly:

TDS:	8,000 ppmw	6,200 ppmw
Hourly PM_{10}	2.83 lbs	2.19 lbs
24-hour PM_{10}	67.9 lbs	52.6 lbs
Annual PM_{10}	12.1	9.4 tons

The AERMOD modeling analysis was then re-run using a new pollutant ID to enable the program to predict the highest-high 24-hour concentration, and with the revised PM_{10} emissions rate. The analysis showed a highest modeled 24-hour PM_{10} concentration of 4.9 $\mu g/m^3$, which is below the significant impact level.[259] The Air District published these revised numbers and the

[257] *Guideline on Air Quality Models*, 40 C.F.R. Part 51, Appendix W (July 1, 2008), § 7.2.1.1.b., applicable to PSD Air Quality Impact Analyses per 40 C.F.R. § 52.21(*l*)(1).

[258] *See* Section 3.2.5 Specifying the Pollutant Type of User's Guide for the AMS/EPA Regulatory Model-AERMOD - EPA-454/B-03-001, September 2004.

[259] *See* Russell City Energy Center Modeling Files; Summary of Air Quality Impact Analysis for $PM_{2.5}$ From the Russell City Energy Center, attached to Memorandum from Glen Long to Weyman Lee, July 27, 2009 (identifying the maximum predicted impact, *i.e.*, "highest first high concentration", for $PM_{2.5}$ as 4.9 $\mu g/m^3$).

supporting analysis in the Additional Statement of Basis and received no further comment on this issue. The Air District is therefore finalizing Condition No. 44 in the final permit to reflect this lowered TDS limit, as proposed in the August 2009 Draft Permit.

Comment XIII.A.3. – Use of Existing Monitoring Data To Assess Ambient Air Quality at Project Location:

The Air District received comments stating that it should conduct monitoring at the specific project location, rather than relying existing monitoring data as representative of ambient air quality conditions at the project location.

Response: EPA's PSD regulations provide that existing monitoring data can be used in the PSD Air Quality Impact Analysis where the permitting agency determines that it is representative of conditions at the project location.[260] As explained below in response to Comment XIII.A.4., the Air District has determined that the monitoring data from its Fremont-Chapel Way monitoring station is sufficiently representative of the air quality conditions at the project location for use in the Source Impact Analysis.

Comment XIII.A.4. – Location of Meteorological and Background Air Quality Monitoring Data:

The Air District also received comments questioning the representativeness of the meteorological data and background air quality data that the District used in its analysis. The comments suggested that that meteorological data from Oakland Airport and the background ambient air quality data from the Fremont-Chapel Way Monitoring Station would not be representative of the project location. The comments suggested that data from Oakland or Hunters Point in San Francisco would be more representative of Hayward air quality. The comments also questioned why the District does not maintain a monitoring station in Hayward. Some comments questioned whether the Air District has conducted air monitoring in Hayward over the past 10 years.

Response: The Air District reviewed the meteorological and background air quality data it used in response to this comment, and has concluded that the data is representative of conditions in the vicinity of the project location. For the meteorological data, data from the Automated Surface Observing System (ASOS) at the Oakland International Airport was used. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. The Oakland meteorological surface data (OAK) is representative of conditions at the Russell City Energy Center project site, based upon the requirements for representativeness set forth in the EPA's Guideline on Air Quality Models.[261] The Guideline on Air Quality Models states the following

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[260] *See* NSR Workshop Manual at p. C.18. ("the applicant may use existing ambient data [where it is] judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate."); *see also In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 128 (EAB 1997); *In re Hibbing Taconite Co*., 2 E.A.D. 838, 851 (Adm'r 1989).

[261] *See* 40 C.F.R. Part 51, Appendix W, Section 8.3 (Meteorological Input Data).

conditions should be considered when determining if weather data is representative: (1) the proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected. The Oakland Airport data satisfies all four of these criteria for representativeness and is appropriate for modeling the proposed project. Both the Oakland Airport and the proposed project location are along the East Bay shoreline with similar predominant upwind fetches. The AERSURFACE analysis showed that both sites had similar land use characteristics. Both sites are located on simple terrain in similar proximity to the complex terrain to the east. The Oakland Airport site is a permanent National Weather Service/Federal Aviation Administration weather installation that operates 24 hours per day. The most recent five years of data at the time (2003-2007) were used for this modeling study. Based upon this comparison, the Oakland ASOS data is representative of the proposed project location and meets all USEPA data completeness requirements.

With respect to the ambient air quality data the Air District used from the Fremont-Chapel Way monitoring station, that data is representative of the background air quality at the project location, based upon the criteria EPA has established for assessing representativeness. EPA provides for monitoring data of this type to be used if it is sufficiently representative based on three factors: (i) monitor location, (ii) the quality of the data, and (iii) the currentness of the data.[262] The Fremont-Chapel Way data is representative under all three of these criteria. The Fremont-Chapel Way monitoring station is located approximately 18 km southeast of the project in an area within the same air basin and with the same general geography and level of development. In addition, the data from the Fremont-Chapel Way monitoring station is complete and of high quality, and it is current (2006-2008). The Air District has therefore concluded that the Fremont-Chapel Way monitoring data is representative and appropriate for use in assessing the impacts from the proposed facility.[263]

The Air District published this further analysis of the representativeness of the background data it used in the Additional Statement of Basis. During the second comment period, the Air District received further comments criticizing the use of the Fremont-Chapel Way monitoring data. The comments stated that the two zip codes near the proposed project location have higher rates of diseases such as heart disease, respiratory disease, heart failure, pulmonary disease, and asthma than the Alameda County average, and that this suggests a higher level of vulnerability to these diseases in these zip codes than in the rest of the county. The Air District disagrees that this situation, to the extent that it exists, means that the Fremont-Chapel Way monitoring data are inappropriate for the project location. The fact that certain areas may contain populations with increased environmental sensitivities is taken into account when the applicable air quality

[262] *See* NSR Workshop Manual, Section III.A., p. C.19.

[263] The Air District also notes that the Fremont-Chapel Way monitoring station is a "population oriented" station, meaning that it was sited at a location that will be determinative of the air pollution levels to which the majority of the population will is exposed. *See* 2008 Air Monitoring Network Plan, submitted by the Air District to EPA on July 1, 2009, at pp. 5, 32 (available at www.baaqmd.gov/Divisions/Technical-Services/Ambient-Air-Monitoring/~/media/35693B885FB249E7996FABE033A3F070.ashx). This fact further underscores the usefulness of using this monitoring site.

standards are established, as the NAAQS have built into them a margin of safety to ensure that they are health-protective for all populations. It does not mean that it is inappropriate to use monitoring data from a representative location that meet EPA's requirements for PSD analyses.

The Air District also received comments during the second comment period stating that the District should use data from Oakland or San Francisco as more representative. The comments justified this suggestion by stating that those locations would be more appropriate because smog comes to Hayward from Oakland and San Francisco and is lesser in Fremont. The Air District disagrees that Oakland or San Francisco would provide a more representative picture of existing pollutant levels at the project site. The Fremont-Chapel Way data is highly representative under EPA's representativeness criteria as discussed above, and these comments do not suggest otherwise or suggest any reason why Oakland or San Francisco data would be more representative under these criteria. Moreover, a brief review of monitoring data from those locations show that they actually record *lower* levels of ambient air pollutant than the Fremont-Chapel Way location, contrary to the assertion in the comments.[264] The use of Oakland or San Francisco background data would therefore be *less* conservative, and the Air District declines the commenters' invitation to do so.[265]

Finally, in response to the comments suggesting that the Air District should establish a monitoring station in Hayward, the Air District notes that maintaining a monitoring station is an expensive endeavor, and given the District's resource constraints it can only maintain a certain number throughout the entire Bay Area. The Air District maintains several monitoring sites in the East Bay, which provide a good understanding of air quality conditions in the area given the District's resource constraints. The Air District will consider the needs for a monitoring station in Hayward, and in all other relevant areas in the East Bay and larger Bay Area, in its future planning for maintaining a representative monitoring network that will give an accurate picture of ambient air quality conditions.

Comment XIII.A.5. – Accuracy of Emissions Data and Modeling Results:

The Air District received several comments objecting to the emissions data that the Air District used as inputs for its modeling analysis. Comments claimed that the data used in the modeling

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[264] *See* Glen Long 10/7/09 email, comparing $PM_{2.5}$ (24-hour) at San Francisco-Arkansas Street and Fremont, showing Fremont at 29 $\mu g/m^3$ background level and San Francisco at a 26 $\mu g/m^3$ background level. The Air District also notes that the Fremont-Chapel Way location was chosen as a monitoring site specifically because it is downwind of sources of air pollution and therefore is a more conservative location to use as a measurement of background air pollution concentrations. (*See* 2008 Air Monitoring Network Plan, submitted by the Air District to EPA on July 1, 2009, at p. 31 (available at www.baaqmd.gov/Divisions/Technical-Services/Ambient-Air-Monitoring/~/media/35693B885FB249E7996FABE033A3F070.ashx.)

[265] The Air District also notes that the San Francisco Hunters Point monitoring station referenced in some of the comments was operational only for a one year period, from June 2004 through June 2005, and thus is lacking sufficient data to be considered representative. The closest currently-operational District monitoring station to Hunters Point is the Arkansas Street monitoring station, but as discussed herein the Air District disagrees that it would be more representative.

came from the applicant's operation of other power plants and could be subject to potential bias or inaccuracy. Comments also questioned the statistical limits of confidence associated with the modeling results and suggested that the modeling results may not be accurate for these reasons. Comments noted that conditions in the Bay Area vary widely from day to day, with times of heavy fog and cloud ceiling and other times of very hot and still weather, for example. These comments suggested that the modeling may not take such variables into account. Some comments also stated that the Source Impact Analysis improperly assumes that the facility will be operating 24 hours per day, whereas in fact it may shut down and restart on some days and will not necessarily operate for the full 24 hours on any particular day. These comments stated that the modeling should include all emissions that could occur during actual operation, including startup and shutdown emissions.

Response: The Air District based the emissions data that it used as inputs for its modeling analysis on the maximum emission rates that will be allowed for this facility based on the legally enforceable permit conditions that the Air District is imposing. The Air District disagrees with the comments that this approach was inappropriate or that it fails to recognize the actual emissions from this facility. The Air District also disagrees that the modeling program it used is not sufficiently accurate. The Air District used the AERMOD modeling program, which is approved by EPA and represents the state-of-the-art methodology for assessing ambient air impacts from emission sources. This modeling program does take weather conditions into account, and includes meteorological data from a monitoring station in the vicinity of the project site. With respect to basing the modeling on an assumption that the source will be operated 24 hours a day, the Air District based its emissions inputs on the maximum emissions that will be allowed per day.[266] These limits will be the applicable limits for the facility regardless of how it operates. If the facility has increased emissions during part of the day from startups and shutdowns, it will have to reduce operations during other parts of the day to ensure that emissions stay within the daily limit. For all of these reasons, the Air District therefore disagrees with the comments that the emissions inputs it used in its modeling were inappropriate.[267]

Comment XIII.A.6. – Designation of Project Location as "Rural" for AERMOD Modeling:

The Air District received comments questioning whether the site location should have been designated as "rural" for the purposes of the AERMOD air quality impact modeling, given the

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[266] *See* Summary of Air Quality Impact Analysis for The Russell City Energy Center Memorandum, attached to Memorandum from Glen Long to Weyman Lee, November 6, 2008, subject: Russell City Energy Center, Permit Application # 15487, (hereinafter, "2008 AQIA Summary"), p. 2.

[267] In addition, the applicant stated that the facility will be operated only when dispatched pursuant to the terms of a power purchase agreement with PG&E. The applicant stated that the description of the facility's operation as meeting "spot sale demand" in the Statement of Basis was not entirely correct, because it will be dispatched only pursuant to the power purchase agreement. The Air District acknowledges this comment, but notes that the terms used to describe the operating scenario do not alter the PSD permitting analysis. It is the project's emissions, not the words used to describe the operating scenario, that govern the permitting analysis.

development to the east of the project site. In this context, the commenters alluded to the fact that some areas near the project may be zoned for and used as urban, industrial land.

Response: The "Rural" designation for purposes of AERMOD modeling is simply a variable that is used as an input in the model. It reflects the fact that the level of development in the project area is not of the intensity where increased surface heating due to the urban heat island effect would be expected. This designation is a 'term of art' based on an Auer land use analysis.[268] The Air District's selection of the "Rural" designation for purposes of AERMOD modeling does not mean that the District considers the entire area to be rural in character. The Air District agrees with the comments that areas in the project vicinity are light industrial in nature, but would like to clarify for the record that this does not mean that running the AERMOD model with a "rural" setting is inappropriate. To the contrary, the "rural" designation is appropriate for this facility based on the Auer land use analysis.

The Air District published this further explanation of the "Rural" designation in the Additional Statement of Basis and invited further comment on it. The Air District received further comments stating that it should have used the "multiple urban" option instead because the facility would be located in a metropolitan area governed by different jurisdictions and zoned for light industrial, commercial, and single- and multi-family residential. Other commenters also suggested that the "single urban" option might be appropriate. The District also received comments stating that the "Rural" designation was inappropriate because the official slogan of the City of Hayward is "the Heart of the Bay".

In response to these further comments, the Air District again reviewed the Auer land use analysis for the project. The Air District examined land uses within 3 kilometers of the project location as directed by EPA's Guidelines. Based on 2005 Association of Bay Area Governments parcel-level land use data, the land within this area was found to be classified 52% rural and 48% urban, making "Rural" the appropriate designation for the analysis. The "Rural" designation here means that there is not likely to be any significant urban heat island effect in the area in which the facility will be located.[269] This is an appropriate assumption here, because the facility will be located near a large body of water (the San Francisco Bay) as well as surface water and marsh lands, and the winds blow predominantly onshore from the west, resulting in little heat island effect. The Air District also notes that the three-kilometer radius used in the Auer land use analysis is the same three-kilometer distance that EPA uses for investigating the impacts of shoreline fumigation from a large body of water. This point further highlights that the marine layer, not the urban heat island, will dominate in the area near the shoreline where the project will be located.

Furthermore, to demonstrate that selection of the "Urban" designation would not result in any significant difference in modeled impacts, the Air District ran the model to evaluate impacts with respect to $PM_{2.5}$ – the PSD pollutant that generated the greatest amount of public comment – using the "Urban" designation. The difference in the modeled $PM_{2.5}$ impact was insignificant, and in any event was actually a *decrease* compared with the "Rural" designation: the modeling showed impacts of 0.53 $\mu g/m^3$ (annual average) using the "Rural" designation, but only 0.47

[268] *See* Guideline on Air Quality Models, 40 CFR Pt. 51, App. W, § 7.2.3.c. and note 73.
[269] *See id.*

μg/m^3 (annual average) using the "Urban" designation.[270] But in any event, as explained above, the requirements for conducting the modeling analysis require that the "Rural" option be selected because less than 50% of the area with three kilometers of the project site is industrial, commercial, or residential.[271]

The Air District therefore disagrees with these comments because the Auer land use analysis clearly shows that the "Rural" designation should be used, and additionally because even if an "Urban" designation were appropriate here, there is no indication that it would make any difference in the outcome of the Air Quality Impacts Analysis.[272] In addition, the Air District also disagrees with the comment citing Hayward's official slogan as a reason for using the "Urban" setting. A City's slogan is not relevant to air quality impact modeling or any other PSD permitting issues.

Comment XIII.A.7. – Use of Data and Modeling Results:

The Air District received comments claiming that the Air Quality Impacts Analysis does not demonstrate how the computer modeling translates to the real world context where impacts would be made. The comments complained that information in the analysis is provided in tables, but only once in graphic form and even then without including a scale or other relevant information. The commenter complained that the assumptions made regarding the choice of models and the interpretation of data is not discussed.

Response: The Air District used the modeling program required by EPA for PSD permitting analysis. (*See* EPA's Guideline on Air Quality Models, 40 C.F.R. Part 51 Appendix W). This modeling program represents the state-of-the-art methodology for determining what the ambient air quality impacts will be from a source of emissions. The results of this analysis were fully explained and clearly presented in the Statement of Basis and Additional Basis and supporting documentation. The Air District disagrees that the use of this modeling program or the discussion of the results was inappropriate or unclear (although the Air District appreciates this comment and will continue to work to ensure that its analyses are as clear and accessible as possible to interested members of the public).

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[270] *See* $PM_{2.5}$ Urban Modeling AERMOD Files, G. Darvin, Atmospheric Dynamics. This analysis focused on annual $PM_{2.5}$ impacts because now that the Bay Area is designated as non-attainment for the 24-hour standard, that standard no longer applies for PSD permitting. But even when one considers the 24-hour standard, the difference resulting from using the "Urban" designation would be insignificant. The maximum 24-hour average $PM_{2.5}$ concentration predicted from the proposed facility's emissions was 4.97 μg/m^3, as opposed to 4.88 μg/m^3 using the "Rural" designation, a difference of less than 2%.

[271] Regarding the use of the "multiple urban" option, that option is only applicable when modeling sources over larger domains and in different urban areas (*e.g.* San Francisco vs. Oakland). Because all of the sources that were modeled are located in one area, the "multiple urban" option is not appropriate and the AERMOD model will not allow it to be chosen.

[272] The Air District notes that none of the commenters stated that the analysis would reach a different ultimate conclusion if the "Rural" setting were not used, which is consistent with the Air District's conclusion.

Comment XIII.A.8. – Completeness of Information Presented in Analysis:

The Air District received comments regarding the December 2008 Statement of Basis suggesting that the Air Quality Impact Analysis's Table II (which presents emissions rates used for modeling for different pollutants and averaging times) and Table III (which presents the maximum predicted ambient air quality impacts that would result from the project) are incomplete.

Response: The Air District reexamined these tables in response to these comments and did not find that they were incomplete in any way. Certain boxes in these tables do not have data in them, but that is because they are not applicable, not because the information is incomplete. For example, in Table II, there are no emission rates provided for NO_2 and CO for the cooling tower because the cooling tower is not a source of emissions of these pollutants. To give another example, short-term emission rates are not provided for NO_2 because the NO_2 standard is an annual standard. The Air District did not put data in these boxes because it was not relevant to the PSD Air Quality Impact Analysis. The Air District explained this situation in the Additional Statement of Basis and invited members of the public to identify any specific areas where they believe data that is relevant and necessary to the Air District's analysis may be missing. The Air District did not receive any further comments in this issue.

Comment XIII.A.9. – Changes Made Since Earlier 2007 Air Quality Impacts Analysis:

The Air District received comments pointing out some changes that the District made in the Air Quality Impact Analysis it issued in connection with its December 2008 Statement of Basis and proposed permit, compared with the analysis issued in connection with the District's 2007 permitting actions. For example, the comments pointed out that the analysis used for the December 2008 Statement of Basis concludes that the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$, whereas the analysis used for the 2007 permitting actions states that it will be 370 $\mu g/m^3$.

Response: The modeling for the 2007 permitting actions was performed using the model ISCST. EPA has made that model a non-guideline model, and it has been replaced with AERMOD, the current EPA guideline model. The analysis used for the December 2008 Statement of Basis was performed using AERMOD, and represents the current best assessment of what project impacts will be. As the commenter noted, the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$.[273] The Air District published this explanation in the August 2009 Additional Statement of Basis and received no further comment.

Comment XIII.A.10. – Shoreline Fumigation Analysis for Startup Emissions:

The Air District received comments questioning whether the impact of startup emissions was taken into account in the Air District evaluation of shoreline fumigation issues.

Response: Fumigation occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground level when unstable air below reaches plume level. Shoreline fumigation can occur for sources located within 3 km of a large body of water, such as this

[273] 2008 AQIA Summary, *supra* note 266, at p. 6, Table VI (reporting maximum combined impact plus maximum background).

facility which will be located near the San Francisco Bay. In response to these comments, the Air District ran a further shoreline fumigation analysis assuming maximum startup emissions for carbon monoxide. (For NO_2, the NAAQS is an annual standard and so the annual emissions rate, which takes into account startup emissions, is used in the shoreline fumigation analysis. For particulate matter, there is no difference in the emissions limits for startups and other operations and so the analysis for steady-state operations is the same for startups. For these reasons, carbon monoxide is the only pollutant for which it is necessary to conduct a shoreline fumigation analysis specific to startup emissions.) The analysis showed that even with higher emissions expected during startups, the impacts would still be below the PSD Significant Impact Levels used for screening purposes. The Air District has concluded that even in startup mode, the facility's emissions will not cause or contribute to any violation of the NAAQS or increment.[274] The results of the modeling analysis are summarized in Table 6 below.

Table 6: Russell City Energy Center – Maximum Ambient Air Quality Impact for Carbon Monoxide for Shoreline Fumigation

Averaging time	Shoreline Fumigation Impact	Significant Impact Level
1-hour	177.8	2000
8-hour	327.5	500

B. Air Quality Impact Modeling and Analysis Issues Related to $PM_{2.5}$

As discussed above in Section VI (regarding Particulate Matter), the PSD regulatory requirements for $PM_{2.5}$ permitting have been evolving during the course of this permit proceeding. At the time the Air District published its initial proposal in December of 2008, EPA required that its "surrogate policy" be used and that an analysis of PM_{10} impacts should be used to address $PM_{2.5}$ issues. EPA subsequently stayed that requirement and proposed to repeal it, and so the Air District determined that reliance on the surrogate policy was not appropriate and that an analysis of $PM_{2.5}$ specifically was required. The District therefore completed an Air Quality Impact Analysis for $PM_{2.5}$ impacts, which it published in connection with the August 2009 Additional Statement of Basis.[275] At that time, the San Francisco Bay Area was still designated as "attainment/unclassifiable" for $PM_{2.5}$ for both the 24-hour and annual standards, and so the Air District evaluated the facility's impacts with respect to both standards in the Air Quality Impact Analysis. The analysis found that the facility would not cause or contribute to an exceedance of either standard. (*See* Additional Statement of Basis at pp. 84-92.) Subsequently, the Bay Area's redesignation as non-attainment for the 24-hour NAAQS became effective, making $PM_{2.5}$ subject to Non-Attainment NSR requirements and making PSD requirements inapplicable for this pollutant (for the 24-hour standard, at least). As explained in detail in

[274] *See* G. Long, Memorandum regarding Shoreline Fumigation, attached with email from G. Long to A. Crockett, Dec. 10, 2009.

[275] Several comments criticized the District's initial reliance on its PM_{10} analysis as a surrogate for analyzing $PM_{2.5}$ impacts, in accordance with EPA's surrogacy policy. When EPA reversed its position on that policy, the Air District agreed with these comments and undertook the $PM_{2.5}$ analysis. The $PM_{2.5}$ analysis is the Air District's response to these comments.

Section VI, the Air District is conservatively treating this "split" designation as meaning that the facility is subject to Non-Attainment NSR permitting for the 24-hour standard (to the extent applicable), but remains subject to PSD permitting requirements for the annual standard. The Air District addressed the applicable BACT requirements for $PM_{2.5}$ in Section VI, and addresses the Air Quality Impact Analysis requirements here.

As explained in the Additional Statement of Basis, the Air District has examined the potential impacts of the facility's emissions on ambient $PM_{2.5}$ concentrations, and has found that the facility will not cause or contribute to an exceedance of the annual $PM_{2.5}$ NAAQS. The Air District received comments on this conclusion and the underlying analysis, and responds to these comments below. The Air District also received comments on the analysis it published concluding that the facility's emissions will not cause or contribute to an exceedance of the 24-hour NAAQS, but now that the Bay Area is designated Non-Attainment that analysis is not part of the PSD permitting analysis. As a result, these comments are no longer relevant to the District's decision on whether to issue the permit, and the District is not required to respond to them here. Nevertheless, since the Air District has considered the comments and has found that they do not change the outcome of the analysis, the District is publishing responses to them in this document. The Air District stresses that these issues with respect to the 24-hour standard are not a part of the PSD permit, but the District is addressing them anyway because they have been the subject of public interest.[276]

Before turning to the specific comments, the Air District summarizes the $PM_{2.5}$ Source Impact Analysis it undertook in connection with the August 2009 Additional Statement of Basis. The analysis was based on work submitted by the project applicant in consultation with Air District staff,[277] and the District reviewed and documented the results of that work.[278] As described in the Additional Statement of Basis (*see* pp. 84-89) and in the Air District's and applicant's reports, the Air District applied the two-step methodology set forth in the NSR Workshop Manual. (*See* NSR Workshop Manual, Chapter C.) The first step of the analysis is the "preliminary analysis", in which the facility's $PM_{2.5}$ emissions are modeled and their impacts on ambient $PM_{2.5}$ concentrations are compared with a "Significant Impact Level" ("SIL"). A SIL is a screening level used to determine whether a full impact analysis is required; for projects that have no modeled impacts above the SIL, the analysis ends.[279] EPA has not finalized SILs for $PM_{2.5}$ yet, and so the Air District applied SILs derived from EPA's SIL for PM_{10}. The Air District used SILs of 1.2 $\mu g/m^3$ for 24-hour average $PM_{2.5}$ concentrations and 0.3 $\mu g/m^3$ for

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[276] The District also notes that to the extent that in the unlikely event that EPA's 24-hour $PM_{2.5}$ Non-Attainment designation is stayed, rescinded, or otherwise rendered inapplicable, the District's responses will also serve as a basis for showing that the facility's emissions will not cause or contribute to a violation of the 24-hour NAAQS.

[277] *See* Atmospheric Dynamics, Inc., *$PM_{2.5}$ PSD Source Impact Analysis for the Russell City Energy Center Draft Prevention of Significant Deterioration (PSD) Permit* (June 2009)), revised July 30, 2009 (hereinafter, "$PM_{2.5}$ PSD Source Impact Analysis").

[278] *See* Summary of Air Quality Impact Analysis for $PM_{2.5}$ From the Russell City Energy Center, attached to Memorandum from Glen Long to Weyman Lee, July 27, 2009 (hereinafter, "$PM_{2.5}$ AQIA Summary").

[279] *See* NSR Workshop Manual, pp. C.24-C.25.

annual average $PM_{2.5}$ concentrations.[280] These levels are $3^1/_3$% and 2% of the respective $PM_{2.5}$ NAAQS for the 24-hour and annual NAAQS, which is the same percentage that EPA uses for the PM_{10} SILs. Since these percentages are appropriate for PM_{10}, the Air District has concluded that they are appropriate percentages to base a SIL on for $PM_{2.5}$, a similar pollutant. These are also the most conservative of the three approaches that EPA has proposed in its current SIL rulemaking proposal. Applying these SILs, the Air District determined that the facility would cause impacts above the SIL at several locations. Under the two-step methodology prescribed by the NSR Workshop Manual, when impacts are above the SIL the analysis must proceed to the second step, the "full impact analysis".

To conduct the full impact analysis, the Air District identified an "impact area" for further analysis, which is a circular area around the facility location with a radius out to the farthest point at which an impact was modeled above a SIL. The farthest location with an impact above any SIL was located 8.1 km from the facility, at which there was a modeled impact above the 24-hour SIL of 1.2 $\mu g/m^3$. In accordance with EPA policy, the Air District then established a circular "impact area" with a radius of 8.1 km around the facility location in order to conduct a full impact analysis.[281] The Air District then considered the cumulative impact of the facility's emissions, background ambient air concentrations, and emissions from other nearby sources on receptors located within this impact area. The facility's contribution was based on modeling using the facility's emissions, and the background contribution was based on the Fremont-Chapel Way monitoring data as discussed above. For the contribution from other nearby sources, the Air District undertook a search of its database of $PM_{2.5}$ sources within a radius of 6 miles (9.7 km) around the facility location that have been permitted since January 1, 2007, and located a total of 29 such sources (including 21 backup diesel generators). The Air District also evaluated non-point sources within this area that could cause a significant concentration gradient at any of the areas where the facility's impact was above the SIL. The Air District identified a portion of Highway 92 that is located approximately 1 km south of the facility as such a non-point source, and included it in the analysis. The cumulative impact from all of these contributions (the facility, the 29 point sources, and Highway 92) was then modeled for each receptor location within the impact area where the facility's impact was above the SIL.

[280] The Air District compared both the 24-hour and annual impacts with their respective SILs, even though the facility is now subject only to PSD requirements for the annual standard, because at the time the Bay Area was still designated as attainment/unclassifiable for the 24-hour standard.

[281] In accordance with EPA policy, the Air District established the impact area based on the farthest exceedance of either SIL. Now that PSD is no longer applicable for the 24-hour standard, the analysis for the annual standard would need to look only at the farthest exceedance of the annual standard, which was closer than 8.1 km. The most distant impact above the annual SIL was at only 450 meters. The impact area for the annual SIL is therefore only 63.6 hectares in size, whereas the Air District considered the larger impact area of 20,612 hectares based on the 24-hour standard. Rather than redo the analysis with this smaller area, the Air District continued to rely on the larger impact area since even using that larger area the analysis shows no significant contribution to any NAAQS exceedance. The Air District considers the use of this larger area – over 300 times larger in size than the impact area that would result from using the annual SIL – to add a high degree of conservatism to its analysis.

Based on this cumulative analysis, the District evaluated whether the highest 98th percentile (highest 8th high) $PM_{2.5}$ ambient air concentrations would be above the NAAQS at any receptor location. This analysis found that the maximum total combined annual-average ambient air concentration that would occur at any location would be 10.56 $\mu g/m^3$, which is well below the annual NAAQS standard of 15 $\mu g/m^3$. The proposed project therefore satisfies the Section 52.21(k) NAAQS compliance requirements for the annual $PM_{2.5}$ standard. The facility will not cause or contribute to a violation of the annual $PM_{2.5}$ NAAQS.

As noted above, the District's analysis also evaluated 24-hour impacts, even though 24-hour impacts are no longer part of the PSD analysis. The District summarizes the results here as well for purposes of providing the public with additional information, since several commenters discussed the results in their comments. As with the annual analysis, the 24-hour analysis evaluated whether the highest 98th percentile (highest 8th high) $PM_{2.5}$ ambient air concentrations would be above the NAAQS at any receptor location where the project's contribution would be above the 1.2 $\mu g/m^3$ SIL.[282] This evaluation examined whether the modeled concentration from the proposed facility plus other modeled sources would be above 6.0 $\mu g/m^3$ at any such receptor location, because the background level is 29.0 $\mu g/m^3$, meaning a further increase above 6.0 $\mu g/m^3$ would exceed the 24-hour NAAQS of 35 $\mu g/m^3$. The analysis concluded that there would not be any locations where both the project's contribution would be above 1.2 $\mu g/m^3$ and the total contribution from the project plus the other modeled sources would be above 6.0 $\mu g/m^3$. The analysis did find some locations where the total contribution from all modeled sources was over 6.0 $\mu g/m^3$. For example, the highest 98th percentile modeled concentration from these sources was 11.27 $\mu g/m^3$. But in each of these situations, the project's contribution at that location was well below the SIL, meaning that the project would not be causing or contributing to any NAAQS violation within the meaning of Section 52.21(k).[283] Similarly, the analysis found some locations where the project's contribution was above the SIL, but in each of these situations the total contribution from all modeled sources was below 6.0 $\mu g/m^3$. This situation arises from the fact that when the wind is from the northwest, the project's impacts can sometimes exceed the SILs, but at those times the wind is blowing the contributions from other sources (such as Highway 92) in the other direction and not causing an exceedance of the NAAQS. Similarly, when the wind is blowing from the Southeast, emissions from sources like Highway 92 can cause exceedances of the NAAQS within the impact area, but at those times the wind is blowing the project's contribution the other way such that the project's emissions are below the SIL. Thus, even if the 24-hour standard were still applicable as part of the PSD permit analysis – which it is not anymore – the District would conclude that the project satisfies the Section 52.21(k) NAAQS compliance requirements for the 24-hour $PM_{2.5}$ standard.

The Air District also addressed PSD increment exceedance in the Additional Statement of Basis. The Air District determined that the project cannot cause an exceedance of a PSD increment for

[282] EPA guidance requires the highest 98th percentile value is used because compliance with the NAAQS is determined on this basis. *See* Appendix W, Section 10.1.c.

[283] *See* NSR Workshop Manual at p. C.52 ("The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation.").

$PM_{2.5}$ because EPA has not established any $PM_{2.5}$ increments yet. EPA has proposed increments, however, and so the District also examined whether the facility would exceed any of the proposed increments if they had been finalized. EPA's proposed Class II increments are 9 $\mu g/m^3$ and 4 $\mu g/m^3$ for the 24-hour and annual standards, respectively, and the facility's maximum impacts of 4.9 $\mu g/m^3$ and 0.5 $\mu g/m^3$, respectively, are well below these levels. Thus even if the proposed increments were in effect today, the facility would not cause any exceedance of them. (Again, the 24-hour standard is no longer applicable for PSD permitting, but the Air District provides the increment consumption discussion as a matter of public information.)

Finally, the Air District also undertook an analysis of the potential for impacts at the Point Reyes National Seashore, a federal Class I area that is located approximately 62 km from the project. The analysis concluded that the project will not have any significant air quality impact on any Class I area.[284]

The Air District published its analysis in the Additional Statement of Basis and supporting documents, and received a number of comments on these issues during the second comment period.[285] The Air District responds to these comments on $PM_{2.5}$ issues in this section. The Air District responds to comments regarding the annual $PM_{2.5}$ standard because it is conservatively assuming that the annual standard is still applicable for PSD permitting under the Bay Area's "split" attainment designation (non-attainment for the 24-hour standard and attainment/unclassifiable for the annual standard). The Air District is also responding to issues raised regarding the 24-hour standard, even though the 24-hour standard is no longer applicable for PSD permitting. Although those issues are no longer relevant to the PSD permit analysis and the comments are therefore not something that the Air District is required to respond to, the District nevertheless is providing responses to provide the public with as much information as possible regarding this project. The Air District appreciates the public's interest and input on these issues, even if they are no longer part of the PSD permitting analysis.

Comment XIII.B.1. – SIL Exceedance and Requirement to Conduct Full Impact Analysis for $PM_{2.5}$:

During the first comment period, the Air District received a number of comments stating that it should conduct an Air Quality Impact Analysis for $PM_{2.5}$. Some of the comments noted that the maximum modeled ambient $PM_{2.5}$ impact exceeds at least one of EPA's proposed SIL for $PM_{2.5}$. The comments claimed that when a SIL is exceeded, a full impacts analysis must be conducted to determine whether the NAAQS may be violated.

Response: After the first comment period, the Air District changed its position and determined that PSD review was required for $PM_{2.5}$ specifically, and that it was no longer appropriate to rely on the surrogate policy. The Air District therefore conducted a $PM_{2.5}$ Source Impact Analysis and found that impacts would be above the lowest of EPA's proposed SILs as noted by the comments, which the Air District agrees is an appropriate number to use to determine

[284] *See* $PM_{2.5}$ AQIA Summary, *supra* note 278, at p. 11.

[285] The Air District also published the results of a $PM_{2.5}$ visibility analysis (*see* Additional Statement of Basis at 89 & note 157), but did not receive any further comments on this issue.

significance in this analysis. The Air District therefore conducted a full impacts analysis as outlined above.

Comment XIII.B.2. – Basis for $PM_{2.5}$ "Significant Impact Levels":

The Air District also received comments stating that EPA has not yet finalized its proposed SILs for $PM_{2.5}$, and so the District must develop its own SILs if it wants to rely on SILs in the Source Impact Analysis. The comments suggested that in relying on EPA's lowest proposed SIL, the District has not provided adequate justification for that number. The comments also cited an important appellate opinion involving SILs, *Alabama Power v. Costle*, and stated that this case requires an agency to justify SILs by demonstrating that the burdens of regulation will not yield significant benefits. The comments also criticized EPA's proposed SILs as not being justified by such a showing. The commenters criticized the proposed SILs as arbitrary and based on "ratios" that are not justified; they claimed that it does not make sense to have a single national SIL that will apply to all areas of the country; they claimed that the air in the San Francisco Bay Area is very close to exceeding the NAAQS and so a small impact can have great significance; and they stated that the proposed SIL that the District used is 13% of EPA's proposed PSD increment, which they stated was a significant amount of deterioration in an area that is already in violation of the NAAQS.

Response: The Air District disagrees that its use of $PM_{2.5}$ SILs in its Source Impact Analysis for this project is inappropriate. To the contrary, the Air District believes that its analysis represents an appropriate, conservative means of satisfying the requirements of the PSD program in the absence of any final rulemaking from EPA. As the commenter correctly noted, the concept of application of *de minimis* thresholds is clearly rooted in the decision of *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1980) and in longstanding EPA policy and practice.[286] The use of SILs by state permitting agencies pending finalization of EPA's SIL rulemaking is also supported by the EPA Response to Comments document cited in these comments, which expressly states that states can develop and apply SILs pending finalization of the rulemaking.[287]

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[286] *See, e.g.,* Prevention of Significant Deterioration (PSD) for Particulate Matter Less than 2.5 Micrometers ($PM_{2.5}$) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Proposed Rule, 72 Fed. Reg. 54112, at 54138 (September 21, 2007) (hereinafter, "September 21, 2007 Proposed Rule") ("Based on EPA interpretations and guidance, SILs have also been widely used in the PSD program as a screening tool for determining when a new major source or major modification that wishes to locate in an attainment or unclassifiable area must conduct a more extensive air quality analysis to demonstrate that it will not cause or contribute to a violation of the NAAQS or PSD increment in the attainment or unclassifiable area."); *In Re Prairie State Generating Company*, *supra* note 6, slip op. at pp. 137-144 and additional authorities cited therein.

[287] *See* EPA, Office of Air Quality Policy and Standards, Air Quality Policy Division, New Source Review Group, Response to Comments, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers in Diameter ($PM_{2.5}$), March 2008, p. 82. To the extent that the comments on this issue were intended to imply that a state agency has to go through a formal rulemaking process before using a $PM_{2.5}$ SIL, the Air District disagrees. There is nothing in any EPA guidance that would require a formal rulemaking process in order for a state to use a $PM_{2.5}$ SIL.

In short, the Air District believes that under EPA's PSD permitting program it is fully authorized to use SILs in its Source Impact Analysis, and has substantial discretion to do so as it considers in the manner that it considers most appropriate and justified (at least until EPA finalizes its proposed SILs).

Moreover, the Air District disagrees that the 0.3 μg/m^3 SIL that it used to evaluate potential impacts on annual $PM_{2.5}$ concentrations, which corresponds to the lowest and most conservative of EPA's proposed SILs for the annual standard, is not adequately justified. This SIL threshold level was derived using the same *de minimis* percentage of the $PM_{2.5}$ NAAQS as was used in deriving the SIL for PM_{10}, a similar class of pollutant. For PM_{10}, EPA has determined that an increase in ambient PM_{10} levels of less than 2% of the annual PM_{10} NAAQS can be considered *de minimis* for purposes of the PSD analysis. EPA has therefore established the annual PM_{10} SIL at 1.0 μg/m^3, which is 2% of the annual PM_{10} NAAQS (50 μg/m^3).[288] Applying this same 2% *de minimis* rationale for the annual $PM_{2.5}$ NAAQS of 15 μg/m^3 results in a significance level of 0.3 μg/m^3, which is the SIL that the Air District used in its $PM_{2.5}$ analysis.[289] Since EPA has established by final regulation that it is justifiable to set the *de minimis* SIL level for PM_{10} at 2% of the NAAQS, the Air District has concluded that it is similarly justifiable and appropriate to set the *de minimis* SIL level for $PM_{2.5}$ at 2% of the NAAQS, at least on an interim basis until EPA can finalize its rulemaking.[290]

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[288] *See* 40 C.F.R. § 51.165(b)(2) (1.0 μg/m^3 SIL for annual PM_{10}). The analysis of 24-hour impacts is no longer required now that the Bay Area has been redesignated as non-attainment, but to the extent that it is still relevant the District notes that the SIL it used for the 24-hour analysis – 1.2 μg/m^3 – is valid for the same reasons as the annual SIL. It was based on the same *de minimis* percentage of the NAAQS as EPA used for the 24-hour PM_{10} SIL. The 24-hr PM_{10} SIL is 5.0 μg/m^3, which is $3^1/_3$% of the 24-hour PM_{10} NAAQS. (*See id.*) The 1.2 μg/m^3 24-hr $PM_{2.5}$ SIL the Air District used in its analysis is the same $3^1/_3$ percentage of the 35 ppm 24-hour $PM_{2.5}$ NAAQS.

[289] Further discussion on the how these SILs are justified is contained in EPA's proposed SIL rulemaking, 72 Fed. Reg. at 54140. The Air District has reviewed this rationale and believes that it demonstrates that these SILs are appropriate and justified for use here. The Air District therefore disagrees with the implication that it is blindly following EPA's proposal without any independent review and judgment. To the contrary, the Air District believes in its own independent professional judgment that the proposed SILs are appropriate here for the reasons explained in this Response.

[290] The Class I SILs the Air District used were developed in a similar manner, based on the established Class I SILs for PM_{10}. EPA developed a PM_{10} annual Class I SIL of 0.2 μg/m^3, which is 0.4% of the annual PM standard of 50 μg/m^3. Taking 0.4% of the annual $PM_{2.5}$ standard (15 μg/m^3) results in an annual $PM_{2.5}$ Class I SIL of 0.06 μg/m^3. Similarly, EPA developed a PM_{10} 24-hour Class I SIL of 0.3 μg/m^3, which is 0.2% of the 24-hour PM_{10} standard of 150 μg/m^3. Taking 0.2% of the 24-hour $PM_{2.5}$ standard (35 μg/m^3) results in a 24-hour $PM_{2.5}$ Class I SIL of 0.07 μg/m^3. Additionally, as an alternative way to establish the $PM_{2.5}$ SILs, the Air District following the approach EPA used when it developed its PM_{10} SILs, which was to set the SILs at 4% of the increment. According to EPA, setting the Class I SILs in this manner was based on its belief that, "where a proposed source contributes less than 4% to the Class I increment, concentrations are sufficiently low so as not to warrant a detailed analysis of the

The Air District also notes that using this approach for establishing SILs for $PM_{2.5}$ is supported by a number of other permitting agencies and similar entities. Besides being proposed by EPA (as the lowest and most conservative of three alternatives being considered by that agency), this rationale has been followed in developing SILs by several other states, the Northeastern States for Coordinated Air Use Management ("NESCAUM"), and the National Association of Clean Air Agencies.[291] The fact that these other air permitting agencies recommend using this same approach further supports the District's determination that, in its judgment, a 0.3 $\mu g/m^3$ SIL is appropriate for the permitting analysis here.[292]

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combined effects of the proposed source and all other increment-consuming emissions." (72 Fed. Reg. at 54140.) By calculating the ratio of the $PM_{2.5}$ to PM_{10} NAAQS for both the annual and 24-hour standards (0.3 and 0.24, respectively) and then applying these ratios to the PM_{10} increments, long- and short-term Class I $PM_{2.5}$ increments of 1 and 2 $\mu g/m^3$ were derived, which, upon application of EPA's recommended 4% factor, results in proposed annual and 24-hour Class I SILs of 0.04 and 0.08 $\mu g/m^3$ (respectively). This was the approach that EPA used in developing "Option 1" in its proposed $PM_{2.5}$ SIL rulemaking. (*See* 72 Fed. Reg. at 54140.) Believing that either of these options would provide a sound basis for developing appropriate interim $PM_{2.5}$ SILs – at least until EPA finalizes its $PM_{2.5}$ SIL rulemaking – the Air District then conservatively took the lower result for each of the long- and short-term SILs, which resulted in application of an annual Class I $PM_{2.5}$ SIL of 0.04 $\mu g/m^3$ and a 24-hour Class I $PM_{2.5}$ SIL of 0.07 $\mu g/m^3$.

[291] *See, e.g.*, NESCAUM Technical Guidance on Significant Impact Levels (SILs) for $PM_{2.5}$ Revised NESCAUM Permit Modeling Committee, December 8, 2006; available at: www.nescaum.org/focus-areas/science-and-technology/science-and-technology-documents; CTDEP Interim $PM_{2.5}$ New Source Review Modeling Policy and Procedures, Gina McCarthy, Commissioner, Connecticut Department of Environmental Protection, issued August 21, 2007, restated February 11, 2009 at: www.ct.gov/dep/lib/dep/permits_and_licenses/air_emissions_permits/nsrmodelingplan.pdf; Interim Permitting and Modeling Procedures for Sources Emitting between 10-100 Tons per Year of $PM_{2.5}$ (Fine Particulate) (Revised to include 2008 $PM_{2.5}$ Monitoring Data), State of New Jersey, Department of Environmental Protection, Division of Air Quality, March 17, 2009; available at: www.nj.gov/dep/aqpp/downloads/PM-2.5modelingpolicy_Mar2009.pdf; letter, Northeastern States for Coordinated Air Use Management, to Docket ID No. EPA-HQ-OAR-2006-0605, Re*:* NESCAUM Comments on EPA's Proposed Rule: Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)–Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC). 72 Federal Register 54111, September 21, 2007, December 13, 2007; available at: www.nescaum.org/documents/nescaum-comments_psd-increment_sil_smc-20071213-final.pdf/; letter from National Association of Clean Air Agencies to U.S. EPA Air and Radiation Docket, Re: Docket ID: EPA-HQ-OAR-2006-0605, January 17, 2008; available at: www.4cleanair.org/documents/PM25Increments.pdf.

[292] Note also that in practice the Air District applied a much higher and more conservative SIL in determining the impact area than was necessary, which resulted in a much larger and more conservative impact area than was necessary. This is because the Air District used the 24-hr SIL of 1.2 $\mu g/m^3$ to establish the impact area, which resulted in an impact area with a radius of 8.1 km, even though the 24-hr analysis is no longer required for PSD permitting. The Air District

Finally, with respect to the remainder of the criticisms of the SILs the Air District used, these focus primarily on the 24-hour analysis, which is no longer applicable. For example, commenters objected that the 24-hour SIL the Air District used should not be considered a *de minimis* amount because it constitutes 13% of the proposed 24-hour increment, and in the commenters' view any amount above 10% of the total increment should not be *de minimis*. But this argument does not hold for the annual SIL the District used, which is less than the 10% level at which the comments suggested the impact would cease to be *de minimis*.

Similarly, other comments objected to using a *de minimis* SIL analysis in an area that is very close to or already exceeding the NAAQS. But again, this argument applies primarily to the 24-hour $PM_{2.5}$ NAAQS, as the Bay Area has a much greater compliance margin for the annual NAAQS. Moreover, to the extent that the Bay Area's status as being already in violation of the 24-hour NAAQS as a factual matter has until recently created anomalies when applying a PSD analysis to 24-hour $PM_{2.5}$ impacts, this situation was the result of the time lag in EPA's formal legal designation of the Bay Area as non-attainment. This situation meant that until recently the District has been required to apply the PSD rules under 40 C.F.R. section 52.21, when it should appropriately be applying the Non-Attainment NSR rules under Appendix S since the region is not in attainment of the 24-hour standard. To the extent this situation led to anomalies, such as using SILs to demonstrate that a facility would not cause or contribute to a violation of the NAAQS for 24-hour $PM_{2.5}$ in a region that was already in violation of the NAAQS for that pollutant as a factual matter, this situation arose because of the time lag in EPA's designation, not because of any defect in EPA's proposed SILs.

For these reasons, the Air District disagrees with the comments that the SILs it used were inappropriate, unjustified, or arbitrary. The Air District also observes that none of the comments offered any alternative rationale that would be more appropriate in establishing a *de minimis* level of impacts to use as SILs here under the principles expressed in *Alabama Power v. Costle*. The Air District has therefore concluded that its use of SILs in the Source Impact Analysis was appropriate under EPA's PSD regulations, and that it supports the District's determination that the facility will not cause or contribute to a violation of any NAAQS or PSD increment.

Comment XIII.B.3. – Inclusion of Precursors in the $PM_{2.5}$ Analysis:

The Air District also received comments stating that it should take NOx and ammonia emissions into account in its $PM_{2.5}$ Source Impact Analysis, asserting that these emissions are precursors to secondary $PM_{2.5}$ formation.

With respect to NOx, the comments stated that the District should include NOx in its analysis because NOx is "presumed in" under EPA's $PM_{2.5}$ implementation rule.[293] The comments

was required to use only the annual SIL in this analysis, which is much lower at 0.3 $\mu g/m^3$ and would have resulted in a much smaller impact area of only 0.45 km in radius. (*See supra* note 281.) This approach resulted in even more conservatism in the analysis.

[293] *See* 73 Fed. Reg. 28321, 28328 (May 16, 2008). "Presumed in" is EPA shorthand for the agency's treatment of NOx as presumptively a PM2.5 precursor unless it can be demonstrated

claimed that the District was improperly relying on EPA's SIL proposal, which directs agencies to use only direct $PM_{2.5}$ emissions and not precursors in applying the SILs, for not including NOx emissions in its $PM_{2.5}$ calculations (as well as on informal guidance from EPA staff on this issue). The comments also claimed that the preamble for EPA's SIL proposal suggests that NOx emissions should be included in the Source Impact Analysis because language in the preamble stated that EPA evaluated both direct $PM_{2.5}$ emissions and secondary $PM_{2.5}$ resulting from other pollutants such as NOx when it evaluated its proposed increment levels. The commenters stated that because EPA evaluated both direct $PM_{2.5}$ and secondary $PM_{2.5}$ from these precursors when it evaluated its proposed increments, the Source Impact Analysis should take NOx into account when evaluating whether the facility will cause or contribute to a violation of the NAAQS. The comments also stated that air in the Bay Area has more available ammonia than nitric acid (*i.e.*, is "nitric-acid limited"), such that adding additional nitric acid will cause the nitric acid to react with ammonia to form ammonium nitrate, which will add to $PM_{2.5}$ levels. (The comments implied that additional NOx emissions will add to nitric acid in the atmosphere and lead to this reaction.) The comments also stated that there are modeling tools available to undertake an analysis of NOx emissions on secondary $PM_{2.5}$ formation. In this regard, the commenters cited language from EPA's Guideline on Air Quality Models (40 C.F.R. Part 51, Appendix W) discussing regional models, which states that regional models are not designed for evaluating individual sources but notes that such models can be of use in the context of regional transport of secondary particulates. The commenters also cited District Regulation 2-2-303 and stated that the District's willingness to allow inter-pollutant trading between NOx and particulate matter for offset purposes further supports incorporating NOx emissions into the $PM_{2.5}$ Source Impact Analysis as a $PM_{2.5}$ precursor.

With respect to ammonia, comments stated that ammonia emissions would form secondary particulate matter. The comments questioned the Air District's analyses in the Statement of Basis and Additional Statement of Basis finding that ammonia slip from the facility would not contribute to the formation of secondary particulate matter. The comments suggested that the memorandum the District cited in support of its conclusion that the Bay Area is nitric-acid limited – on which the conclusion that ammonia will not cause significant secondary $PM_{2.5}$ formation was in part based – was specific only to the San Jose and Livermore areas and cannot be used to support a determination for the Hayward area. The comments also stated that Air District staff were reevaluating the District's conclusion that ammonia slip emissions do not contribute to secondary particulate formation as expressed in the earlier memorandum. The commenters claimed that the Air District should assess the potential for ammonia slip from this facility to contribute to secondary particulate matter formation.

Response: The Air District disagrees that it is required to include NOx emissions in its $PM_{2.5}$ analysis. Nevertheless, in response to these comments the Air District has undertaken an assessment of precursor emissions on secondary $PM_{2.5}$ formation using a regional transport model and has found that including precursors would not make a significant difference in the results of the analysis. The Air District therefore disagrees with these comments that the potential for precursor emissions to cause secondary $PM_{2.5}$ formation suggests that the District

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that NOx emissions are not a significant contributor to the region's ambient PM2.5 concentrations.

should revise the analysis's ultimate conclusion: that the facility will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. The Air District's analysis is set forth in the following discussion:

- *NOx as a Precursor To Secondary PM2.5 Formation:*

First, the Air District disagrees with the comments that including NOx emissions in the $PM_{2.5}$ analysis is required under EPA's PSD regulations. EPA has made clear in its SIL rulemaking that it interprets the $PM_{2.5}$ analysis not to include NOx emissions as a precursor, as all of the alternatives it is considering in its rulemaking proposal would include only "*direct* $PM_{2.5}$ emissions from the new stationary source" in the demonstration that the facility will not cause or contribute to an exceedance of the NAAQS.[294]

This interpretation is justified because in most cases, the bulk of the $PM_{2.5}$ impacts will occur near the source. As such, there will be minimal time and travel distance between the emissions point and the impact point, giving little time for secondary $PM_{2.5}$ formation to occur.[295] This situation is present here, as the bulk of the particulate impacts are just outside of the fence-line of the facility, with the remainder only a few miles away.[296]

The Air District also notes that current EPA-approved models do not adequately consider the chemistry necessary to account for secondary $PM_{2.5}$ formation from NOx emissions, which is one of the reasons why EPA has interpreted its proposed SILs taking into account direct $PM_{2.5}$ emissions only.[297] Currently-approved models are dispersion models which predict how

[294] 72 Fed. Reg. at 54149 (proposing 40 C.F.R 51.166(k)(2)); 72 Fed. Reg. at 54154 (proposing 40 C.F.R 52.21(k)(2)) (emphasis added).

[295] This justification was cited by the Northeastern States for Coordinated Air Use Management (NESCAUM) and by the National Association of Clean Air Agencies as a reason for presumptively excluding NOx emission from the $PM_{2.5}$ impact analysis. *See* letter, Northeastern States for Coordinated Air Use Management, to Docket ID No. EPA-HQ-OAR-2006-0605, Re*:* NESCAUM Comments on EPA's Proposed Rule: Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)–Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC). 72 Federal Register 54111, September 21, 2007, December 13, 2007; available at: www.nescaum.org/documents/nescaum-comments_psd-increment_sil_smc-20071213-final.pdf/; letter from National Association of Clean Air Agencies to U.S. EPA Air and Radiation Docket, Re: Docket ID: EPA-HQ-OAR-2006-0605, January 17, 2008; available at: www.4cleanair.org/documents/ PM25Increments.pdf. The fact that these associations interpret the PSD source impact analysis to exclude NOx as a precursor to secondary $PM_{2.5}$ formation further supports the Air District's interpretation.

[296] *See* $PM_{2.5}$ AQIA Summary, *supra* note 278, at p. 5; $PM_{2.5}$ PSD Source Impact Analysis, *supra* note 277, at p. 12.

[297] *See*, *e.g.*, Draft Modeling Protocol for $PM_{2.5}$, Regional/State/Local Modeler's Workshop, Philadelphia, May 2009, slide no. 6; available at: www.cleanairinfo.com/regionalstatelocalmodelingworkshop/archive/2009/presentations/05%20Weds%20PM/2009rsl_Draft%20Modeling%20Protocol%20for%20PM25.pdf; New Source Review: $PM_{2.5}$ NSR Rules, Region 4 Modelers' Conference, March 17, 2009, slide no. 43; available at: www.epa.gov/Region4/air/modeling/2009%20Workshop/March-17-

directly-emitted particulate matter will impact ambient air concentrations; they are not photochemical models that predict how precursors may react with each other in the atmosphere to form secondary particulate matter. Without sufficient tools available to accurately assess the potential for secondary $PM_{2.5}$ formation, the Air District would risk engaging in speculation in trying to quantify what the potential for this effect might be. EPA has made clear PSD permitting decisions should not be based on speculation.[298]

For all of these reasons, the Air District disagrees that inclusion of NOx in the air quality impact analysis as a precursor to secondary $PM_{2.5}$ is required for PSD permitting.

- *Ammonia as a Precursor To Secondary $PM_{2.5}$ Formation:*

With respect to ammonia, EPA has established that ammonia is "presumed out" as a $PM_{2.5}$ precursor, and is not included as the PSD analysis. (*See generally*, discussion in Response to Comment No. VI.2. above.) Based on this clear regulatory direction from EPA about what to include in the PSD permitting analysis for $PM_{2.5}$, the Air District disagrees that it should or could include ammonia in its source impact analysis as a precursor to secondary $PM_{2.5}$ formation.

Moreover, beyond these legal requirements excluding ammonia slip from federal PSD permitting, the Air District has found that the Bay Area – and in particular the area where the facility will be located – is nitric-acid limited and that additional ammonia emissions will therefore not cause significant additional secondary $PM_{2.5}$ formation.[299] As discussed in Response to Comment No. VI.2. above, secondary particulate formation mechanisms are highly complex and it is therefore difficult to state with certainty what the conditions in the Bay Area are. But the Air District has used a computer model to simulate how emissions $PM_{2.5}$ precursors will impact regional ambient $PM_{2.5}$ concentrations, which District staff reviewed in response to comments that the 1997 memorandum cited in earlier documents was outdated. The Air District's draft report on its computer modeling exercise concludes that regional ammonium nitrate buildup is limited by nitric acid, not by ammonia.[300] The draft report does find that the amount of available nitric acid is not uniform but varies in different locations around the Bay Area, and consequently the potential for ammonia emissions to impact $PM_{2.5}$ formation varies around the Bay Area. Specifically, according to the draft report, the model predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes

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09/DeroeckREGION%204%20PRESENTATION%20PM2.5%20NSR%20IMP+%20Increments17_4.ppt. The Air District received comments critical of looking to informal EPA guidance documents such as these, but the District believes that such informal documents can be useful in arriving at sound permitting decisions. Obviously, this informal guidance is not binding in the way that a regulation would be, but where it provides sound reasoning it can be helpful in interpreting how to apply the PSD requirements appropriately.

[298] *See, e.g.*, *In re Three Mountain Power*, 10 E.A.D. 39, 57-58 (EAB 2001).

[299] The memorandum at issue is the Sept. 8, 1997, Office Memorandum from D. Fairley to T. Perardi & R. De Mandel entitled "A first look at NOx/Ammonium nitrate tradeoffs", discussed on pp. 26-27 of the Statement of Basis and pp. 55-56 of the Additional Statement of Basis.

[300] *See* BAAQMD, Draft Report, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Draft, Oct. 1, 2009), at p. E-3 & p. 30. The Air District anticipates issuing a final report shortly.

in ambient $PM_{2.5}$ levels of between 0% and 4%, depending on the availability of nitric acid, leaving open the potential that ammonia restrictions could form a useful part of a regional strategy to reduce $PM_{2.5}$.[301] The draft report therefore restates the general conclusion from the 1997 "first look" memorandum that the Bay Area is nitric-acid limited, although it finds that reductions in the region's ammonia inventory could potentially achieve reductions in $PM_{2.5}$ concentrations in areas that may have sufficient available nitric acid.[302] (The draft report cautions that its assumptions regarding the availability of nitric acid may be misleading, however, because of the preliminary nature of the ammonia emissions inventory used for modeling.) Notably, the model predicts that the Hayward area, like the Livermore and San Jose areas, has among the lowest levels of available nitric acid in the entire region, in the vicinity of 0.25 ppb or less.[303] This last finding suggests that the study from the 1997 "first look" memorandum regarding the Livermore and San Jose areas would be useful in assessing the situation in the Hayward area. Thus, after evaluating this issue further based on all of the evidence before it, the Air District continues to conclude that the evidence at this stage shows that additional ammonia emissions from the Russell City facility will not make a significant additional contribution to secondary $PM_{2.5}$ formation. The Air District therefore disagrees that it should be required to include ammonia in the source impact analysis for this additional reason as well.

- *CMAQ Modeling Of Secondary $PM_{2.5}$ Formation:*

The Air District disagrees with the comments that it was required to include NOx and/or ammonia as precursors in its $PM_{2.5}$ analysis for the reasons discussed above. Nevertheless, the Air District understands the concern underlying these comments and the importance of $PM_{2.5}$ issues, and so it explored the commenters' suggestion to use a regional transport model as a simple way of generating a rough estimate of what the additional impact of precursor emissions might be. Per the comments' suggestion, the Air District used the Community Multiscale Air Quality (CMAQ) model to estimate the secondary $PM_{2.5}$ impacts from the proposed project's emissions of all $PM_{2.5}$ precursors, including NOx and ammonia. The CMAQ model is a photochemical grid model with state-of-the-art-science capabilities for modeling multiple pollutants including fine particles. It is different in this respect than the dispersion models normally used for assessing particulate matter impacts, which allows it to address secondary $PM_{2.5}$. This type of model is a regional model and it is not intended for modeling the impacts associated with individual facilities, and it has not been approved by EPA for this purpose. But the Air District used this model in an attempt to assess the impacts from all $PM_{2.5}$ precursors that will be emitted by the Russell City facility.

The Air District chose a particular period for analysis when the Bay Area experienced an historically high $PM_{2.5}$ event between December 2, 2006 and February 2, 2007. The CMAQ model was run for this base case period, once without the proposed project's emissions and then again, adding the proposed facility's emissions of NOx, reactive organic compounds (ROG), sulfur dioxide (SO_2), and ammonia (NH_3). To reflect the potential "6x16" operating profile of the proposed facility (six days a week, sixteen hours a day at baseload), it was assumed that the

[301] *See id.* at pp. E-3 – E.4.
[302] *See id.* at p. 30.
[303] *See id.*, Figure 17, p. 31.

proposed facility did not operate on Sundays. The model was run for the entire 63-day period.[304] Daily average surface concentrations of $PM_{2.5}$ were computed for each of the 185 x 185 surface grid cells for each run. The cell-by-cell concentration differences (deltas) were then calculated.

The greatest difference in modeled concentrations between the scenarios with and without the proposed facility's emissions of precursors occurred in the grid cell in which the proposed facility is located. The difference in 24-hour concentration in that grid cell is 0.11 $\mu g/m^3$.[305] Assuming that this 24-hour difference extended over the course of a full year (a highly conservative assumption), the facility would still not cause or contribute to an exceedance of the annual $PM_{2.5}$ NAAQS. As described in the Additional Statement of Basis, the maximum impact from direct $PM_{2.5}$ (including background and other nearby sources) was found to be 10.56 $\mu g/m^3$. Even assuming an additional impact of 0.11 $\mu g/m^3$ from secondary $PM_{2.5}$ formation, that would still make a total impact of only 10.67 $\mu g/m^3$, which is still well below the annual NAAQS of 15 $\mu g/m^3$.[306] (Note that the 24-hour standard is no longer applicable for PSD purposes, now that the region has been designated as non-attainment for that standard. But even if it were still applicable, a 0.11 $\mu g/m^3$ additional impact from secondary particulate formation would not cause or contribute to any modeled violation of the standard. The Air District and applicant have confirmed that, adding the maximum secondary particulate impacts (0.11 $\mu g/m^3$) would not result in the exceedance or violation of any $PM_{2.5}$ significance level or standard at any point where the facility's impact would be above the SIL.) Based on this computer modeling, the Air District continues to conclude, based on the best available information, that the facility would not have any significant secondary $PM_{2.5}$ impacts and would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS, even if precursors had to be included in the PSD source impact analysis.

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[304] Selection of a discrete period of historic maximum $PM_{2.5}$ concentrations for purposes of the NAAQS compliance demonstration is consistent with EPA guidance on application of more sophisticated regional models. (*See, e.g.*, Guideline on Air Quality Models, 40 C.F.R. Part 51, App. W, § 5.2.2.1 ("Control agencies with jurisdiction over areas with secondary PM-2.5 problems are encouraged to use models which integrate chemical and physical processes important to the formation, decay and transport of these species (*e.g.*, Models-3/CMAQ or REMSAD) . . . . Suitability of a modeling approach or mix of modeling approaches for a given application requires technical judgment, as well as professional experience in choice of models, use of the model(s) in an attainment test, development of emissions and meteorological inputs to the model and selection of days to model.") (internal references omitted).)

[305] *See* D. Fairley, Memorandum, "Analysis of CMAQ Modeling of Russell City Secondary $PM_{2.5}$", attached with email message from D. Fairley to W. Lee, July 9, 2009. This modeling took into account all potential $PM_{2.5}$ precursors, including NOx, ammonia, ROG, and SO_2.

[306] Notably, the impact of NOx, the only "presumed-in" precursor that the facility will emit in amounts over the PSD significance level, was actually *negative*. That is, the CMAQ model predicts that the facility's NOx emissions will actually result in slight *decreases* of secondary $PM_{2.5}$ levels. (*See* D. Fairley, Memorandum, "Russell City CMAQ Model Results Without Ammonia", attached with email message from D. Fairley to B. Bateman & W. Lee, July 9, 2009.) This result may not correspond to actual dynamics, however, as another approach showed a very slight – and not significant – increase in secondary $PM_{2.5}$ from the increase in NOx. (*See id.*)

Comment XIII.B.4. – Selection of Nearby Point Sources For Full Impact Analysis:
The Air District also received comments criticizing its analysis of other nearby sources in the $PM_{2.5}$ Source Impact Analysis. Specifically, these comments criticized the District's analysis of 29 nearby sources that have been permitted by the District since January 2007, which the District analyzed because they may not be adequately represented in the background $PM_{2.5}$ monitoring data. The comments cited EPA guidance that the multi-source modeling must include all nearby point sources that could cause a significant concentration gradient within the proposed source's impact area, and stated that the District has not adequately justified why the 29 sources it included in its modeling represent all such nearby sources. The comments noted that EPA's guidance states that sources as distant as 50 km from the proposed facility should be modeled if they would cause a significant concentration gradient within the impact area, and stated that there are many sources within a 50 km radius that could potentially do so. Some comments claimed that the District should include all emission sources located anywhere within 50 km in its full impact analysis. Other comments stated that the District should explain how it determined that the 29 sources it modeled were the appropriate nearby sources for purposes of the Source Impact Analysis. The commenters also pointed out that these sources should be modeled at their maximum allowable emissions rates.

Response: The Air District disagrees with these comments and believes that it correctly included appropriate nearby sources in its analysis consistent with EPA guidance. According to EPA guidance, the selection of nearby sources should be based on an "impact area" defined by drawing a circle around the site with a radius equal to the distance to the farthest location where an exceedance of the SIL is modeled to occur.[307] The farthest location where the modeling showed an impact above the annual SIL of 0.3 $\mu g/m^3$ was 450 meters (0.28 mi) from the project location.[308] The Air District then looked at all recently-permitted sources within six miles of the project location to see if there were any recently-permitted sources that may not be reflected in the background concentrations the Air District used based on ambient air monitoring data. This survey out to six miles went nearly 20 times farther out than the edge of the impact area. The Air District believes that this is a highly conservative approach to canvassing sources.

The Air District notes that the guidance requires including only sources that are "expected to cause a significant concentration gradient in the vicinity of" the source being reviewed.[309] For PSD purposes, "vicinity" is defined as the impact area, although the location of nearby sources could be anywhere out to 50 km.[310] The Source Impact Analysis must therefore examine the

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307 NSR Workshop Manual at pp. C.26, C.31.

308 *See* $PM_{2.5}$ PSD Source Impact Analysis, *supra* note 277, at pp. 11-12. As explained above, in the August 2009 analysis the Air District identified the "impact area" based on impacts above the 24-hour SIL because the Bay Area was still designated as attainment/unclassifiable for the 24-hour standard and thus PSD still applied for that standard. The resulting impact area based on the 24-hour SIL was 8.1 kilometers in radius. Now that the Bay Area has been designated as non-attainment for the 24-hour standard, that standard is no longer applicable for PSD purposes and the impact area is defined by the annual standard only (to the extent that PSD is even applicable where there is a "split" attainment designation).

309 40 C.F.R. Pt. 51, App. W, § 8.2.3.b; NSR Workshop Manual at C.32.

310 NSR Workshop Manual at p. C.32.

combined impacts of the source under review plus other sources within 50 km that will be expected to cause a significant concentration gradient with the impact area. Furthermore, the Guideline on Air Quality Models requires that the analysis focus on locations where the source's emissions will interact with the emissions from the other nearby sources.[311] The Air District disagrees that its approach of looking out as far as 6 miles away from the facility location was inappropriate under this guidance. Given the likely falloff of ambient concentrations the farther one moves from the source, the Air District finds it highly unlikely that there would be additional sources beyond six miles that could cause a significant concentration gradient within the impact area.[312] Indeed, the Air District considers it unlikely even that most of the sources it found within the 6-mile radius would be likely to cause a significant concentration gradient inside the impact area, but it nevertheless included them all to be conservative as well as for convenience.[313] The Air District concluded that this approach was conservative and justifiable under EPA guidance to ensure that it identified and included all appropriate nearby point sources.[314]

The Air District established this 6-mile search area based on its professional engineering judgment, and continues to believe that the approach is justified. Emphasizing that "[t]he

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[311] 40 C.F.R. Pt. 51, App. W, § 8.2.3.e. ("The impact of nearby sources should be examined at locations where interactions between the plume of the point source under consideration and those of nearby sources (plus natural background) can occur.")

[312] For an idea of how $PM_{2.5}$ levels tend to fall off with distance from an emissions source, see the applicant's sensitivity analysis for Highway 92, which measured ambient $PM_{2.5}$ concentrations as a function of distance from the highway, and found an exponential falloff in concentrations the father one moves from the $PM_{2.5}$ source. (*See* Source Impact Analysis, p. 13, Figure 2, "$PM_{2.5}$ Sensitivity Analysis, Impact vs. Distance from Road for Middle Route 92 Segment".)

[313] It was easier to be overly conservative and just include all of these 29 sources in the full impact analysis, rather than having to evaluate the impacts that each one would have individually inside the impact area to determine if it would cause a significant concentration gradient. The Air District also notes that it did, in fact, model all of these sources at their maximum permitted emissions rates.

[314] Although the full impact analysis is not required for the 24-hour standard now that the Bay Area has been redesignated as non-attainment for the 24-hour standard, the Air District notes that its approach would be appropriate for that standard as well, if it were still applicable. For the 24-hour standard, the vast majority of areas where the facility's emissions will impact ambient concentrations above the SIL are located close to the project site, within 1260 meters. (*See* $PM_{2.5}$ PSD Source Impact Analysis, *supra* note 277, at p. 10, Figure 1.) Going out to six miles is more than sufficient to be conservative in order to capture all sources that could cause a significant concentration gradient in these close-in areas where the facility will have impacts over the SIL. The only other areas where the facility will have impacts above the SIL are in six isolated locations in elevated terrain to the East of the project, which are up to 8.1 km away. The six-mile point-source search encompassed potential sources out beyond those locations as well. Although the six-mile distance does not establish a search limit as far from these SIL-exceedance locations as with the locations closer in to the project site, these more distant locations are less likely to be impacted by significant concentration gradients from nearby sources because of their isolated locations.

number of sources is expected to be small except in unusual situations", the Guideline on Air Quality Models leaves identification of nearby sources to the professional judgment of the permitting agency:

> b. *Nearby Sources*: All sources expected to cause a significant concentration gradient in the vicinity of the source or sources under consideration for emission limit(s) should be explicitly modeled. The number of such sources is expected to be small except in unusual situations. Owing to both the uniqueness of variables involved in identifying nearby sources, no attempt is made her to comprehensively define this term. Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority (paragraph 3.0(b)). This guidance is not intended to alter the exercise of that judgment or to comprehensively define which sources are nearby.[315]

The Draft NSR Workshop Manual further underscores the flexibility and judgment that permitting agencies necessarily need to apply in identifying "nearby sources" as follows:

> In determining which existing point sources constitute nearby sources, the <u>Modeling Guideline</u> necessarily provides flexibility and requires judgment to be exercised by the permitting agency. Moreover, the screening method for identifying a <u>nearby</u> source may vary from one permitting agency to another. To identify the appropriate method, the applicant should confer with the permitting agency prior to actually modeling any existing sources.[316]

The Air District followed this guidance and has applied its best engineering judgment in undertaking the full impacts analysis here. The District disagrees that its approach was inappropriate under EPA's guidance for PSD permitting.

The Air District further notes that none of the comments identified any specific additional point sources that the Air District should have included. (Some comments did identify specific additional non-point highway sources that they thought should be included, which are addressed in the next comment below.) Some of the comments stated that every source within 50 km must be included in the multi-source modeling. But this is not the case under EPA guidance for conducting such analyses, as outlined above. To the contrary, the multi-source modeling includes only nearby sources that will have a significant concentration gradient within the impact area, and focuses only on those areas where the source's emissions will interact with the emissions from the other nearby sources.[317] Other comments simply suggested that there are hundreds of sources, including ports, railyards, refineries and other industrial sources within 50 kilometers of the proposed facility that could potentially result in significant concentration gradients around the project area. But these comments did not identify any evidence of a significant concentration gradient from any such sources anywhere within the impact area as a

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[315] 40 C.F.R. Pt. 51, App. W, § 8.2.3.b.

[316] Draft NSR Workshop Manual, p. C.32 (emphasis in original). District staff also engaged in informal consultation with expert modeling staff at EPA Region 9.

[317] *See* NSR Workshop Manual at p. C.32.; 40 CFR Pt. 51, App. W, § 8.2.3.e. ("The impact of nearby sources should be examined at locations where interactions between the plume of the point source under consideration and those of nearby sources (plus natural background) can occur.")

result of any such sources, let alone at the specific locations where the proposed facility's modeled impacts also exceeded the SIL. The Air District believes that it appropriately exercised its professional judgment in identifying all nearby sources that should have been included in the analysis, and therefore is confident that its conclusion that there will be no locations where the facility's emissions will significantly contribute to any exceedance of the $PM_{2.5}$ NAAQS is correct.

Furthermore, to the extent that the comments are suggesting that the Air District should be required to identify every emissions source within 50 km and then model each source to assess whether it would cause a significant concentration gradient within the impact area, this interpretation is not supported by EPA guidance and the District disagrees with it. EPA's Guideline on Air Quality Models is clear that "[t]he number of such sources [to be modeled] is expected to be small except in unusual situations."[318] Requiring a permitting agency to go beyond such a rule and to model every source within a 50 km radius would be a huge modeling exercise and would unduly burden agencies with resource constraints. This would not be a good use of public resources in a situation where the agency has determined based on its professional expertise that such additional sources are highly unlikely to cause a significant concentration gradient within the impact area. This certainly holds true here, where there are likely hundreds of additional sources (according to one of the comments) located beyond 6 miles but within 50 km, which could supposedly have some potential impact within the significant impact area. Under the interpretation suggested by these comments, the District would be required to model the impacts of all of these sources, based on nothing more than a commenters' speculation that such sources could cause a significant concentration gradient inside the impact area, in order to prove through modeling that there would be no significant concentration gradient. The Air District disagrees with this interpretation.

For all of the foregoing reasons, the Air District disagrees with the comments that it did not appropriately account for nearby point sources in its full impact analysis for $PM_{2.5}$.[319]

<u>Comment XIII.B.5. – Selection of Nearby Non-Point Sources for Full Impact Analysis:</u>

The Air District also received comments stating that in addition to Highway 92, the District should include other highways as "nearby sources" in its full impact analysis, including Interstate 880, additional portions of Highway 92, Interstate 580, Highway 238, Highway 185, and additional arterial roads.

Response: The Air District disagrees that other roadway sections should be included in the full impacts analysis. The Air District properly included all roadway emissions that could cause a significant concentration gradient in the areas where the facility's impacts would be above the SIL. The Air District determined that these other roadway sections, even though they may lie within the 6-mile radius the District used to identify potential nearby sources, would not cause a significant concentration gradient at locations where the project's impacts would be above the

[318] 40 C.F.R. Part 51, App. W, § 8.2.3.b.

[319] Comments suggesting that the Air District should re-circulate further analysis for an additional public review and comment opportunity are addressed in Response to Comment XVII.C.4. below.

SIL. EPA's guidance is clear that the full impact analysis does not need to consider a source as a "nearby" source unless it could result in a significant concentration gradient in the same vicinity as the proposed source's impacts. That is, even if a particular highway segment might generate a significant concentration gradient *somewhere* within the impact area, but not within the same location where the source's impacts also exceed the SIL, then its exclusion from the multi-source full impact analysis is appropriate; so long as the facility's predicted impacts which exceed the SIL do not coincide in both time and location with any potential violation of the NAAQS resulting from the highway segments, then the facility cannot be found to cause or contribute to such a violation.[320] Identifying the location of the proposed facility's impacts, relative to the location of such other sources, no additional sources were identified as "nearby sources" for inclusion in the full impact analysis because none of such sources could reasonably be expected to cause a significant concentration gradient in or around the same location where the proposed facility's impacts were modeled above the SIL. Accordingly, since most of the modeled locations that were above the SIL were in the immediate vicinity of the proposed project, it was appropriate not to model additional sources as part of the multi-source modeling analysis.[321]

Comment XIII.B.6. – Incorrect Identification of Highway Segments:

The Air District received comments stating that it did not use the correct highway segments in its analysis. The comments objected that the segments identified are not located within the impact area for the project and/or are in Contra Costa County, not Alameda County.

Response: The Air District agrees that the highway segments cited in these comments are not the correct segments. The segments were misidentified in the documentation published in August of 2008 because of a typographical error. The applicant's consultant did in fact model the correct highway segments' emissions in the analysis, but the consultant mistakenly cited the names of the highway segments from another spreadsheet included within the Excel workbook when completing the report. Once this error was identified, the applicant's consultant submitted a correction to the Source Impact Analysis.[322] The Air District disagrees that this typographical error changes the substance of the analysis. To the contrary, the substance of the analysis was based on the correct segments, even if they were misidentified in the report. The segments' identification has now been corrected for the record. The Air District appreciates the comments for bringing this oversight to its attention.

Comment XIII.B.7. – Results of AERMOD Modeling Analysis:

Some commenters stated that they ran the Air District's $PM_{2.5}$ modeling data through their air quality modeling program and got different results. They stated that their analysis produced an impact area for the full impact analysis for $PM_{2.5}$ 24-hr impacts that extended out to 11.43 km,

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[320] *See In re Prairie State Generating Company*, *supra* note 6, pp. 137-144 (affirming decision to issue permit where modeled violations of the NAAQS were not coincident in both time and location with the source's modeled impacts above the SIL).

[321] The exponential manner in which the PM2.5 impacts from roadway sources falls off as one moves farther away from the source is discussed further in the Applicant's $PM_{2.5}$ Source Impact Analysis prepared by Atmospheric Dynamics, Inc. (July 30, 2009 revision), at p. 13.

[322] Memorandum from G. Darvin (Atmospheric Dynamics) to G. Long (Bay Area Air Quality Management District), September 28, 2009.

not the 8.1 km that the District used in its analysis. They stated that they calculated that there were 8,424 receptors where the highest modeled impact from the proposed project would exceed the 1.2 $\mu g/m^3$ SIL, not 6,019 as calculated in the District's analysis. These commenters opined that the difference between the outcomes was because the commenters used EPA's AERMOD program whereas the District used a commercial version of the program. These comments were based upon records the commenters construed as indicating that the District's modeling files were generated using "BEE-Line Software". The comments stated that the program used in the District's analysis was a private proprietary program, and that Appendix W does not allow the use of a proprietary model and source code. The comments stated that the District should use the appropriate AERMOD program in its PSD Air Quality Impact Analysis.

Response: The issue of exactly how far out to extend the 24-hour impact area is now moot, as 24-hour impacts are no longer part of the PSD permit review now that the Bay Area has been designated as non-attainment of the 24-hour NAAQS. The Air District therefore disagrees that anything in this comment provides a reason to revisit its permitting analysis. The comment does not contend that use of an 8.1 km impact area for the annual standard was inappropriate, and the Air District observes that an 8.1 km impact area was actually very highly conservative for the annual analysis given that annual impacts above the SIL were not found more than approximately 450 meters from the project site.

The Air District nevertheless responds on the substantive issue raised by these comments in order to provide full information to the public and to assure interested parties that the Air District used the correct approach for a PSD permit analysis. Based upon the Air District's analysis, the discrepancy between the commenter's modeled results and those of the applicant and Air District appears to have resulted from the commenter's use of the wrong emission rate for the gas turbines. The commenters stated that they used an emission rate of 1.134 grams per second (g/s), which they note is higher than the rate of 0.945 g/s specified by the applicant's Source Impact Analysis. Apparently, the commenters selected the wrong emissions rate because the commenters had relied upon an outdated modeling report generated by the Air District, which used the combustion turbine/HRSG emissions rate proposed in the December 2008 Draft Permit (9 lbs/hr), rather than the reduced emissions rate (7.5 lb/hr) proposed in the August 2009 Draft Permit and in the modeling reports referenced in the Additional Statement of Basis. (The higher emission rate of 9 lb/hr equals 1.134 g/s.) According to the Air District's assessment, the differences which the commenter modeled resulted from its use of the wrong emissions rate, and not from any other difference in the modeling inputs or methods.

With respect to the modeling program used, the Air District disagrees that it used a proprietary commercial version of the AERMOD software. To the contrary, the Air District used the same publicly available AERMOD program that the commenters apparently did. The reference to the proprietary "BEE-Line Software" relates to graphical user interface software that makes it easier to input the modeling data that will be used in the AERMOD analysis. This software takes the input information and then organizes it into a format that can be used in the AERMOD program. The actual dispersion model itself that the Air District used, along with the AEMOD input and output files, are based upon the publicly available software. The only additional software that the Air District used was the graphical user interface on the front end to help streamline data inputting. (Note also that the applicant did not use any third-party input programs for the modeling analysis that it provided.) For these reasons, the Air District disagrees with these comments that the District would get different results if it used a different modeling program. The Air District used the same publicly-available AERMOD program as the commenters did, and the discrepancy in the commenters' results comes from the fact that they used incorrect inputs, not because they used a different modeling program. But again, the issue is now moot with respect to the Air District's decision to issue the permit because the 24-hour analysis is no longer part of the PSD permit requirements.

Comment XIII.B.8. – Background Ambient $PM_{2.5}$ Levels:

The Air District also received comments objecting to its reliance upon the convention of using the "highest-eighth-high" 24-hour background concentration for each year of the past three calendar years and averaging them together to identify the appropriate background concentration for use in the multi-source analysis. The comments claimed that this approach was only appropriate for purposes of assessing the attainment/nonattainment status of the area where the monitoring station was located. Rather, according to these comments, the Air District should have used the highest 98th percentile concentration from any single year and applied that as the background concentration, given that the proposed source will operate for 30 years. The comments stated that this approach would have resulted in background levels of $PM_{2.5}$ (24-hour average) of 33.3 $\mu g/m^3$, not the 29.0 $\mu g/m^3$ as used the District's analysis. They claimed that using the 98^{th} percentile figure for the highest single year is more conservative and is consistent with the approach taken by the District's Permit Modeling Guidance (2007), which states that the highest 2^{nd}-high concentration should be used as background for comparison with the national standards. The comments stated that using a more conservative 33.3 $\mu g/m^3$ background, the modeling results show an impact that would cause or contribute to a violation of the NAAQS.

Response: The issue of what 24-hour $PM_{2.5}$ background concentration to use in the 24-hour analysis is now moot, as 24-hour impacts are no longer part of the PSD permit review now that the Bay Area has been designated as non-attainment of the 24-hour NAAQS. The Air District therefore disagrees that anything in these comments provides a reason to revisit its permitting analysis.

The Air District nevertheless responds on the substantive issue raised by these comments in order to provide full information to the public and to assure interested parties that the Air District used the correct approach for a PSD permit analysis. EPA's modeling guidelines that govern the PSD Source Impact Analysis prescribe the use of the three-year average of the 98th percentile of daily average concentrations (the "highest-eighth-high") for determining whether proposed facility would cause or contribute to a violation of the NAAQS.[323] This approach is required for PSD source impact analyses, not just for purposes of determining the attainment/nonattainment status of the area where the monitoring station was located as suggested by these comments. It is set forth in Section 10 of EPA's Guideline on Air Quality Models, which specifies that it is

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[323] *See* 40 C.F.R. Pt. 51, App. W, § 10.1.c. ("Standards for fine particulate matter (PM-2.5) are expressed in terms of both long-term (annual) and short-term (daily) averages. The long-term standard is calculated using the three year average of the annual averages while the short-term standard is calculated using the three year average of the 98^{th} percentile of the daily average concentration.")

applicable for PSD permitting analyses.[324] This approach also reflects generally accepted practice among permitting agencies in issuing PSD permits.[325] The Air District therefore disagrees that its use of the highest-eighth-high background number was inappropriate.

The Air District also disagrees with the comments' assertion that the length of time that the proposed facility will operate should cause the District to depart from EPA's requirements and instead use the highest 98th percentile concentration for any single year as the basis for determining compliance with the 24-hour standard. EPA's Guideline on Air Quality Models was developed specifically with sources such as the proposed facility in mind and there is no indication that the proposed facility's expected life is different than the expected life of any other facility that would be subject to PSD permitting. There is nothing about this situation that would warrant a departure from the EPA Guidelines.

The Air District also disagrees that its Permit Modeling Guidance suggests otherwise. First of all, as a federal PSD permit EPA's Guideline would take precedence over any District guidance. But in any event, the District's Guidance does not differ from EPA's Guideline. The provisions in the District's Guidance on using the highest-second-high in the three-year period as the basis for establishing existing background concentrations is aimed at other criteria pollutants (not including particulate matter) for which the analysis is based on "the highest, second-highest estimated concentration for averaging times of 24-hours or less".[326] The Air District's own policy was intended to reflect the approach to be taken for these other pollutants, and does not reflect the approach to be taken for $PM_{2.5}$, for which the Air District has not yet adopted its own regulations.

For all these reasons, the Air District continues to believe that using the highest-eight-high – the three-year average of the 98th percentile of daily average concentrations – properly establishes background concentrations for the PSD Source Impact Analysis. But in any event, the issue is now moot because the 24-hour standard is no longer part of the PSD analysis. The comments did not make any reference to this issue in connection with the annual $PM_{2.5}$ standard, and in any event the District is not aware of any reason why the annual analysis would be any different even if a single-highest-year approach was used.

[324] *Id.*, § 10.1.a, 10.1.d.

[325] *See*, *e.g.*, CTDEP Interim $PM_{2.5}$ New Source Review Modeling Policy and Procedures, Gina McCarthy, Commissioner, Connecticut Department of Environmental Protection, issued August 21, 2007, restated February 11, 2009 at: www.ct.gov/dep/lib/dep/permits_and_licenses/air_emissions_permits/nsrmodelingplan.pdf; Interim Permitting and Modeling Procedures for Sources Emitting between 10-100 Tons per Year of $PM_{2.5}$ (Fine Particulate) (Revised to include 2008 $PM_{2.5}$ Monitoring Data), State of New Jersey, Department of Environmental Protection, Division of Air Quality, March 17, 2009; available at: www.nj.gov/dep/aqpp/downloads/PM-2.5modelingpolicy_Mar2009.pdf ("The 24-hour background $PM_{2.5}$ value should initially be based on the average of the 98th percentile 24-hour value measured over the latest 3-years of available data.").

[326] 40 C.F.R. Part 51, App. W, § 10.2.3.2.a.

<u>Comment XIII.B.9. – Consideration of Greenhouse Gases on Formation of $PM_{2.5}$:</u>

The Air District also received comments stating that its analysis may have underestimated the impacts on $PM_{2.5}$ concentrations from the facility because of the potential for CO_2 to increase particulate matter formation. These comments cited recent studies published by Mark Z. Jacobson, a researcher at Stanford University, suggesting that increased levels of CO_2 in the local atmosphere can increase local temperatures and alter atmospheric chemistry. According to Dr. Jacobson's studies cited in these comments, increases in CO_2 concentrations in the local atmosphere will reduce $PM_{2.5}$ levels because of higher temperatures, but various other atmospheric processes will cause increases that would more than offset these decreases. The comments stated that the Air District should include the potential effects of increased CO_2 concentrations on $PM_{2.5}$ formation in its $PM_{2.5}$ source impact analysis, based on the findings published by Dr. Jacobson. The comments suggested that the Air District could assess the additional impacts of increase CO_2 concentrations by (i) taking its modeled $PM_{2.5}$ impacts and then applying Dr. Jacobson's approach to adjust that result, or (ii) evaluating how CO_2 emissions will affect temperature and aerosol water content (and presumably other factors related to atmospheric chemistry) and then using that information to adjust the underlying models that are used to predict $PM_{2.5}$ concentrations. The comments stated that if the effects that Dr. Jacobson predicts regarding additional $PM_{2.5}$ formation from increased CO_2 levels are added to the impacts that the Air District has already modeled, the analysis would conclude that the facility will cause or contribute to an exceedance of the $PM_{2.5}$ NAAQS.

Response: The Air District disagrees that it should revisit the $PM_{2.5}$ analysis that it undertook based on Dr. Jacobson's recent research. Moreover, the Air District also disagrees that applying Dr. Jacobson's hypothesis to the results of its analysis would alter the conclusion that the facility will not cause or contribute to a violation of the NAAQS. Even reading Dr. Jacobson's work in the most conservative light possible, it still predicts only a slight increase in ambient $PM_{2.5}$ concentrations, and a small additional impact of this level of magnitude would not change the outcome of the District's analysis.

Before addressing the substance of Dr. Jacobson's research, the Air District first notes that under the PSD regulations it is required to use applicable EPA-approved air quality models as set forth in Appendix W for its Source Impact Analysis.[327] The Air District is therefore bound under EPA's PSD program to use the AERMOD model it used to evaluate $PM_{2.5}$ impacts, and cannot substitute a different analysis based on Dr. Jacobson's research.

Moreover, even if the Air District were free to pick and choose what approach it could take for modeling $PM_{2.5}$ impacts in a Federal PSD permitting analysis, it would be hesitant to include CO_2 as a factor in its modeling based on Dr. Jacobson's paper because of the relatively preliminary nature of Dr. Jacobson's research. The science of atmospheric chemistry is very complicated and there are a large number of variables that will influence the amount of $PM_{2.5}$ that may result in a particular situation, as Dr. Jacobson acknowledges. He notes in his paper

[327] *See* 40 C.F.R. § 52.21(*l*)(1). The regulations allow for modifying such EPA-approved models only in very limited circumstances, upon written approval of the Administrator and after public notice and comment. *See id.* § 52.21(*l*)(2). There is no indication that the Administrator would support departing from the EPA-approved models here based on Dr. Jacobson's paper.

that increases in CO_2 levels will have conflicting impacts on $PM_{2.5}$ levels, with the resulting higher temperatures reducing $PM_{2.5}$ levels and the increased aerosol water content and other factors increasing $PM_{2.5}$ levels. This tension between $PM_{2.5}$ decreases and increases from increases in CO_2 is also borne out in Dr. Jacobson's specific modeling results, which show a range of overall $PM_{2.5}$ impacts from a decrease of 0.007 μg/m^3 throughout California as a whole to an increase of 0.06 μg/m^3 when looking at the Los Angeles area specifically.[328] Dr. Jacobson ultimately concludes that the increases will predominate over the decreases, but the fact that $PM_{2.5}$ levels involve multiple offsetting atmospheric processes and not a single, simple cause-and-effect relationship counsels caution in adopting Dr. Jacobson's hypothesis in a PSD modeling analysis. Furthermore, Dr. Jacobson's research in this area is very recent and there has not been time for a scientific consensus to develop around it with sufficient certainty for it to be used as a basis for a PSD Source Impact Analysis modeling exercise. For all of these reasons, the Air District does not believe that it would be appropriate here to depart from the EPA-approved AERMOD modeling approach it used based on Dr. Jacobson's research at this point. The Air District will continue to monitor the ongoing research in this area to see whether the accepted modeling protocols will incorporate CO_2 levels as an input into the model. But at this point, at least, the Air District disagrees that Dr. Jacobson's study provides grounds for departing from EPA's AERMOD model under 40 C.F.R. Section 52.21(*l*) and 40 C.F.R. Part 51, Appendix W.

Nevertheless, despite the developing nature of the science on this issue and the Air District's determination that it does not justify departing from the AERMOD approach, the District considered what affect Dr. Jacobson's hypothesis – if it is ultimately confirmed – would have on the $PM_{2.5}$ impacts with respect to this facility, as requested in these comments. The Air District followed the first approach suggested in the comments of taking the $PM_{2.5}$ numbers the Air District calculated using AERMOD and then adjusting them using Dr. Jacobson's published research. As noted above, Dr. Jacobson's calculations conclude that anthropogenic CO_2 emissions could affect ambient $PM_{2.5}$ concentrations within a range of a 0.007 μg/m^3 decrease to a 0.06 μg/m^3 increase taking into account all land areas equally (or a 0.041 μg/m^3 to 0.029 μg/m^3 increase on a population-weighted basis). Conservatively taking the most significant modeled increase, Dr. Jacobson's model predicts an increase from anthropogenic CO_2 emissions of 0.8%

[328] *See* Jacobson Paper, *supra* note 35, at p. 12, Figure 1, line 3 ("$PM_{2.5}$ (μg/m^3) (all land)"). These numbers are Dr. Jacobson's published findings taking into account all land areas equally. Dr. Jacobson also calculated "population-weighted" numbers that give more weight to $PM_{2.5}$ increases in populated areas, which resulted in slightly higher numbers (ranging from 0.041 μg/m^3 throughout the entire United States to 0.29 μg/m^3 in the Los Angeles Area specifically). The Air District believes that the numbers based on all land areas make the best comparators for the PSD Source Impact Analysis, since that analysis considers all land and does not use a "population-weighted" approach (although it certainly could be argued that a "population weighted" approach would also be appropriate for a high-population region such as the San Francisco Bay Area). But even taking the higher population-weighted numbers, the broad range that Dr. Jacobson found in his calculations – the high and low numbers differ by a factor of 7 – show how sensitive the tradeoffs between $PM_{2.5}$ increases and decreases can be.

above the ambient concentrations that would otherwise occur.[329] Applying this highest increase predicted by Dr. Jacobson's findings to the maximum total combined ambient air concentration the Air District calculated using AERMOD – which was 10.56 μg/m^3, as described above – the total $PM_{2.5}$ concentration resulting from *all* of the anthropogenic CO_2 emissions included in Dr. Jacobson's study would come to 10.65 μg/m^3. This result, taking Dr. Jacobson's published findings at face value and taking the most conservative impact on $PM_{2.5}$ that he predicts from *all* anthropogenic CO_2 sources, will still be far below the $PM_{2.5}$ NAAQS of 15 μg/m^3. If one were to break out only this facility's CO_2 emissions from all of the other anthropogenic CO_2 emissions sources, which Dr. Jacobson included in his study, the impacts would be even less.[330] But either way, it is clear that even taking Dr. Jacobson's study into account in the manner suggested in these comments, the predicted impacts would still not show a violation of the NAAQS. The Air District therefore disagrees that, even if Dr. Jacobson's approach were applied to the Source Impact Analysis for this facility, it could provide any reason for the Air District to alter its conclusion that the facility will not cause or contribute to a violation of the annual ambient air quality standard for $PM_{2.5}$.

Comment XIII.B.10. – Final Version of Applicant's Source Impact Analysis:

The Air District received comments noting some changes between two versions of the applicant's Source Impact Analysis prepared for the Air District's review by the applicant's consultant, one of which is dated July 27, 2009, and the other of which is dated July 30, 2009. The commenters stated that they disagreed with assertions made by Calpine's counsel that the changes were "minor".

Response: The Air District has evaluated the changes made between the two versions of the applicant's Source Impact Report in response to these comments. The principal difference is that in the initial version, the applicant identified multiple separate "impact areas", including a compact 1.26 kilometer (km) impact area immediately surrounding the project site due primarily to emissions from the cooling tower, and an isolated set of impact areas in elevated terrain to the east of the project site due to emissions from the gas turbines/HRSGs. The applicant claims that it identified impact areas in this manner based on guidance in the NSR Workshop Manual, which provides that "[u]sually the area of modeled significant impact does not have a continuous, smooth border… [but] may actually be comprised of pockets of significant impact separated by pockets of insignificant impact." (*See* Draft NSR Workshop Manual, C-26.) Based on further consideration and on discussions with the Air District, the applicant revised its analysis to define a single impact area that include the entire area within the radius extending out to the farthest

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[329] *See id.* at p. 12, Figure 1, line 2, columns 2 and 3 (increase of 0.29 μg/m^3 compared to ambient concentration of 36 μg/m^3, or 0.8%).

[330] Comments asserted that the facility's CO_2 emissions will be over 10% of all of the CO_2 emissions from within Alameda County. But the County is not the appropriate area for comparing CO_2 emissions even under an analysis of local CO_2 effects such as Dr. Jacobson's. Dr. Jacobson posits that CO_2 will form "domes" over entire metropolitan areas, not individual counties. He specifically identifies the "CO_2 dome" for this region as applying to the entire San Francisco Bay Area, not just an individual county. (*See* Jacobson Paper, *supra* note 35, at p. 3, line 26.) The facility's percentage of CO_2 emissions from the entire Bay Area will be substantially less than 10%.

point where any modeled impact exceeded the SIL. The Air District believes that this latter approach is preferable and more in accordance with the NSR Workshop Manual guidance, and it is this latter approach that the Air District used in its PSD review and analysis in the Additional Statement of Basis. (*See* Additional Statement of Basis at pp. 85-88.[331])

The differences between the initial report and the revised report are immaterial for a number of reasons. First, the Air District followed the latter correct approach in evaluating the Source Impact Analysis; it did not base its decision on the earlier report or the approach identifying multiple impact areas. Furthermore, both analyses examined the entirety of the larger impact area for other sources that might cause a significant concentration gradient within the vicinity of the proposed source's impacts, and included emissions from sources located within the larger impact area, but outside of the smaller identified impact areas. For these reasons, the Air District disagrees that the fact that Calpine described the impact area differently in the earlier version of its Source Impact Analysis makes no difference in the outcome of the PSD Source Impact Analysis review.

Comment XIII.B.11. – Conclusion of No Contribution To A Violation of NAAQS or PSD Increment:

Several commenters questioned how the Air District could conclude that the project's emissions would not cause or contribute to a violation of any NAAQS or PSD increment. In particular, they stated that the Air District is already in violation of the $PM_{2.5}$ NAAQS, and so any additional $PM_{2.5}$ emissions would contribute to that violation.

Response: The fact that the PSD Source Impact Analysis showed no contribution to a violation of the 24-hour NAAQS in a situation where ambient air in the Bay Area already exceeds the NAAQS was the result of several factors. The main factor was that the Bay Area's legal designation as non-attainment had not become effective when the District conducted its analysis, so it had to apply the PSD Source Impact Analysis requirements, which are primarily intended for areas that do not exceed the NAAQS, to be applied. Another factor was that although ambient air in the Bay Area exceeds the 24-hour NAAQS in some places, there are some places where ambient air concentrations are below the NAAQS. As the Air District's analysis showed, the project location was one of them, where background concentrations are at 29.0 $\mu g/m^3$, somewhat less than the NAAQS of 35 $\mu g/m^3$. This allows for some additional impact from the facility without exceeding the standard. And finally, the PSD Source Impact Analysis requirements allow a source to have some emissions even where the NAAQS are exceeded, as long as the facility is not a significant contributor to the exceedance as explained above. For all of these reasons, the PSD Source Impact Analysis for the 24-hour standard found that the facility would not cause or contribute to a violation of the NAAQS. But that conclusion is now moot, of

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[331] Note also that this approach was based on the impacts above the 24-hour SIL, which is no longer applicable since the Bay Area has been designated as non-attainment for the 24-hour standard. The applicable impact area for the annual standard extends only out to the farthest point where the facility will have impacts above the annual SIL, which was only 0.45 km from the project location. So even the using a 1.26 km radius for the impact area would still have been overly conservative. In the end, of course, the Air District used the full 8.1 km radius out to the farthest point with an impact above the 24-hour SIL.

course, as the Bay Area has been redesignated as non-attainment and a 24-hour analysis is no longer required for the PSD permit.

Comment XIII.B.12. – Potential For Impacts Above the SIL in Adjacent Non-Attainment Areas:

Commenters stated that the Bay Area is in non-attainment of the $PM_{2.5}$ NAAQS and that where a source will cause an impact above the Significant Impact Level in a non-attainment area it is not eligible for a PSD permit. The commenters cited some language from the preamble to the proposed $PM_{2.5}$ SIL rule about facilities in attainment areas having impacts in an adjacent non-attainment area.

Response: The commenters are apparently confused in their reading of the rules regarding impacts in adjacent non-attainment areas to mean that any impacts above the SILs here require offsetting emissions reductions. The language and regulatory requirements quoted by the commenters apply in situations where a source is located near the edge of an attainment/unclassifiable area, and emissions from the source may have impacts above the SILs beyond the edge of the attainment/unclassifiable area in an adjacent area that is non-attainment. In such a case, the source must obtain offsetting emissions reductions to compensate for the significant increase in the adjacent non-attainment area. This situation is not applicable here. The source impact analysis does not show any impacts from the proposed facility outside of the San Francisco Bay Area. The only impacts above the SILs are wholly within the San Francisco Bay Area.

The commenters did note that as a matter of fact ambient air quality measurements within that area have been found to be above the 24-hour NAAQS, and based on that data EPA has adopted a non-attainment designation for the Bay Area for the 24-hour NAAQS, although that designation has not yet been published in the Federal Register and so is not yet effective. But even if the Bay Area did have an effective 24-hour $PM_{2.5}$ non-attainment designation, that would not impose the additional PSD permitting requirements that the commenters assert are applicable here regarding providing offsetting emissions reductions as part of the PSD permitting process. If and when the Bay Area's non-attainment designation becomes effective, that will make $PM_{2.5}$ sources subject to Non-Attainment NSR permitting requirements under Appendix S of 40 C.F.R. Part 51, as the District explained in the Additional Statement of Basis. Any requirement for offsets would therefore be subject to the Appendix S rules, not the PSD rules. And as the District explained in the Additional Statement of Basis, Appendix S would not require any offsets for a project of this size.

For all of these reasons, the Air District disagrees with these commenters that the language in EPA's preamble for the proposed SILs rule regarding impacts in adjacent non-attainment areas requires the proposed facility to provide offsetting emissions reductions as part of its PSD permit.

Comment XIII.B.13. – Use of AERMOD to Model Impacts at Point Reyes National Seashore:

The Air District received comments criticizing the modeling that it used to conclude that the project would have no significant impact at Point Reyes National Seashore, a Class I area.

Specifically, the comments criticized the Air District's use of AERMOD for this modeling. The comments stated that AERMOD can be used to model impacts only out to a distance of 50 km from the proposed source, whereas Point Reyes is 62 km away. The comments stated that EPA's modeling guideline, 40 C.F.R. Part 51, Appendix W, states that CALPUFF should be used for modeling impacts at that distance. (The commenters did not state that CALPUFF would give any different results, however.)

Response: Although the Additional Statement of Basis only referenced the previously conducted AERMOD analysis, the applicant had also previously conducted a CALPUFF modeling analysis as well.[332] CALPUFF, as the comments correctly note, is an appropriate regulatory model for evaluation of long-range transport and chemical transformation. In response to these comments, the applicant provided an updated CALPUFF modeling analysis for the impact of the project's emission on Point Reyes National Seashore. To assess the potential for air quality impacts at the nearest Class I area, Point Reyes National Seashore (70 kilometers from the project site), the CALPUFF long-range transport model was used in a screening mode to assess the impacts of particulate matter (PM_{10} and $PM_{2.5}$). The screening mode of CALPUFF uses a 3-dimensional homogeneous meteorological field for simulating transport and dispersion of pollutants for each hour. Specifically, five years of hourly surface and upper air data are required to identify the worst-case impacts when applying CALPUFF in a screening model. The results of the CALPUFF analysis are set forth in Table 7 below, which lists the modeled impacts at the Point Reyes National Seashore Class I area as compared to the Class I SILs and PSD increments.[333]

Table 7: Summary of CALPUFF Class I Modeling Analysis Results

Pollutant	Averaging Interval	Modeled Impact Point Reyes ($\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hr	0.0529	0.07	2
	annual	0.0024	0.04	1
PM_{10}	24-hr	0.0529	0.3	10
	annual	0.0024	0.2	5

This analysis demonstrates that no significant impacts on Class I areas are expected as a result of the proposed project.[334]

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332 Additional details regarding the Class I Impacts Analysis can be found in the earlier submittal, dated February 2007.

333 *See* Summary of CALPUFF Class I Modeling Analysis Results, prepared by Greg Darvin, Atmospheric Dynamics, October 14, 2009. Note that the Class I $PM_{2.5}$ SILs and increments applied by the Air District and appearing in Table 7 were developed in accordance with the methods and rationale described previously. (*See supra* note 290.).

334 The Air District notes that in the Additional Statement of Basis it incorrectly described the Class I SIL. (*See* Additional Statement of Basis at p. 89, citing a Class I SIL of 1.0 $\mu g/m^3$, which would result in a less stringent analysis than described herein.) The Air District did not receive any comments on this issue, but it has nevertheless clarified that the facility will not have Class I

Comment XIII.B.14. – Don Edwards National Wildlife Sanctuary as a Class I Area:
The Air District received comments suggesting that the Don Edwards National Wildlife Sanctuary near the project location should be considered a Class I area for PSD purposes.

Response: The Don Edwards San Francisco Bay National Wildlife Refuge is not designated as a Class I area.[335] The list of Class I areas includes certain international parks, national wildlife areas, national memorial parks, and national parks. The list was initially established by Congress. The process for redesignation of an existing Class II area as a Class I area is set forth by EPA's PSD regulations at 40 C.F.R. 52.21(g).

C. Soils & Vegetation Analysis

The Air District also received a number of comments on its Soils and Vegetation analysis. Some of the comments stated that the Air District should include $PM_{2.5}$ in the analysis, which the District excluded in the initial Statement of Basis based on EPA's PM_{10} surrogacy policy described above. After the first comment period, the Air District departed from that policy and determined that it should include $PM_{2.5}$, which it did in a revised soils and vegetation analysis it published in connection with the August 2009 Additional Statement of Basis. The revised soils and vegetation analysis also updated the biological survey information in response to comments from the public, and also evaluated potential impacts from nitrogen deposition, among other revisions.[336] The Air District then received further comments on these issues during the second comment period. This section addresses all of the comments the Air District received regarding its soils and vegetation analysis during both comment periods.

Comment XIII.C.1. – Analysis of Soils & Vegetation Impacts:
The Air District received a comment objecting that there was no analysis of potential impacts to soils and vegetation (as well as visibility), and that there would be such impacts.

Response: The Air District disagrees with this comment. Impacts to visibility, soils, and vegetation were analyzed in great detail in the Air Quality Impact Analysis, and that analysis was revised and expanded upon in the Additional Statement of Basis. (*See* Statement of Basis, Appendix C; Additional Statement of Basis at pp. 89-91.) The numerous comments the Air District received on these issues highlights the fact that they were discussed at length in these documents. Furthermore, since the close of the comment periods EPA and the US Fish & Wildlife Service have completed their evaluation of the potential for endangered species impacts

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impacts above the correct significance levels, which are set forth above. This issue does not affect the outcome of the Source Impact Analysis, but the Air District notes this correction for the record.

[335] *See* U.S. Department of the Interior, National Park Service, alphabetical listing of all Fish and Wildlife Service Class I areas at: www.nature.nps.gov/air/Maps/FWSTextList.cfm. *See also* "Mandatory Class I Areas", identifying all National Park Service, Fish and Wildlife Service and Forest Service Class I areas at: www.nature.nps.gov/air/Maps/images/ClassIAreas.jpg.

[336] The Air District's Revised Soils and Vegetation Analysis is set forth in Memorandum from Glen Long to Weyman Lee, July 27, 2009.

from the project, which included a review of sensitive species habitat. Those agencies have concluded that there would not be any adverse impact to such habitats. Those findings are discussed in more detail in Response to Comments XIII.C.3., XIII.C.4., and XIX.1.

Comment XIII.C.2. – Survey of Existing Soils & Vegetation Resources:

The Air District received several comments during the initial comment period criticizing the inventory of existing soils and vegetation resources in the vicinity of the project. These comments criticized the use of a soils and vegetation survey conducted for the original Energy Commission proceeding in 2001, and claimed than an updated survey should be used. The comments stated that the inventory based on this older survey mischaracterized the project vicinity in a number of areas. The comments further stated that the soils and vegetation inventory omitted several plant species in the vicinity of the project location because of this situation. Some comments also criticized the survey for being based on just one survey conducted in the spring, which the commenters claimed does not follow accepted protocols that call for multiple visits throughout the blooming season. These comments claimed that the survey therefore missed a population of *Centromadia parryi ssp. Congdonii* (Congdon's tarpant[337]) at a vernal pool in the vicinity of the project, and incorrectly concluded that there is no habitat for this plant in the project area. These comments also stated that the survey does not indicate whether the Hayward Regional Shoreline was surveyed, or whether the hills to the east were surveyed where maximum nitrogen deposition impacts will occur and where there are known rare plant populations.

Response: In response to these initial comments, the Air District revised its inventory of soils and vegetation resources based on an updated survey of the project location as well as a review of the California Department of Fish and Game's California Natural Diversity Data Base ("CNDDB"). This updated inventory is outlined in the revised soils and vegetation analysis for the project, which includes the Congdon's tarplant and all other plant species that were observed or could potentially be found in the vicinity of the proposed project. The Air District published this revised soils & vegetation analysis with the Additional Statement of Basis in August 2009. During the second comment period, the Air District received further comments stating that the revised biological survey for the new site, which was used in preparing the revised Soils & Vegetation Analysis, was incorrect in concluding that there are no populations of Congdon's tarplant within 2 miles of the new site. These comments stated that the person who performed the survey checked the CNDDB and did not find any reported occurrences of Congdon's tarplant, but that there is in fact a population of Congdon's tarplant within 2 miles, at the KFAX radio tower broadcast site, that does not yet appear in the CNDDB. The commenter also re-stated the more general criticisms of the methodology used to conduct the biological survey in general made during the first comment period, voicing generalized criticisms of the quality of the research and analysis underlying the soils & vegetation analysis.

The Air District has reviewed these further comments, but they do not provide any evidence to suggest that the Air District's conclusion that the project will not adversely impact any sensitive plant species is incorrect in any way. While the commenter may have correctly located and

[337] Congdon's tarplant is officially called *Centromadia parryi ssp. condgonii*. It was formerly known as *Hemizonia parryi ssp. condgonii*.

identified a population of Congdon's tarplant on the formerly proposed location for the project, this is not inconsistent with the Air District's analysis. The Air District explicitly identified Congdon's tarplant as a special status plant species that could potentially exist in the vicinity of the project, and included it in the analysis of whether the facility's emissions will have any impacts on such species. The fact that the Air District proceeded on an assumption that there could potentially be such a population in the area, instead of a confirmed identification that there actually is such a population in the area, does not make any difference to this analysis. The further comments on this issue do not claim otherwise, and do not claim that there will in fact be any impacts to the population of Congdon's tarplant that the commenter identified. Furthermore, upon receiving this comment the applicant confirmed that the highest amount of nitrogen deposition predicted to occur at the location where the commenter found the population was approximately 0.21 kg/ha/yr, which is, again, more than an order of magnitude below any threshold of concern.[338] For all of these reasons, the Air District therefore concludes that the conclusion it reached is valid.[339] The emissions from the facility will not cause any significant adverse impacts to any soils and vegetation resources, including any populations of Congdon's tarplant.

Comment XIII.C.3. – Analysis of Potential Soils & Vegetation Impacts from Nitrogen Deposition:

The Air District also received several comments criticizing its soils and vegetation analysis for not considering the potential for impacts from nitrogen deposition as a result of the project. The comments stated that the Air District should evaluate the potential for soils and vegetation impacts in the Hayward Regional Shoreline and in several park areas in the East Bay hills. These comments expressed a concern that non-native vegetation would be able to out-compete native vegetation, which is better adapted to nitrogen-poor soils, if significant additional nitrogen deposition caused those soils to become more nitrogen-rich. These comments also coincided with further evaluation of the potential for nitrogen deposition-related impacts by EPA Region 9 and the Fish & Wildlife Service ("FWS").

Response: In response to these comments, a nitrogen deposition analysis was undertaken for the project, as described in more detail in the Air District's revised soils and vegetation analysis.[340] Nitrogen deposition was modeled using both the AERMIC Model (AERMOD) and CALPUFF air dispersion model. According to the Applicant's assessment, the maximum annual deposition rates calculated by AERMOD in areas potentially occupied by selected species range from 0.02 to 0.37 kilograms per hectare per year (kg/ha/yr), which is more than ten times below the levels

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[338] *See* Nitrogen deposition modeling files, prepared by Gregory Darvin, Atmospheric Dynamics; Nitrogen Deposition Analysis, *infra* note 340, at p.3.

[339] Although the comments stated generalized criticisms of the manner in which the soils and vegetation survey was carried out, they did not cite any specific errors (other than the failure to locate this plant population) or otherwise state that soils and vegetation impacts analysis should have reached a different conclusion. The Air District therefore disagrees that the analysis is defective in any material way.

[340] *See Russell City Energy Center: Nitrogen Deposition at East Bay Regional Parks*, Technical Memorandum from Craig Williams, Biologist, CH2M Hill, to Barbara McBride, Calpine, February 19, 2009, as updated February 29, 2009 (hereinafter, "Nitrogen Deposition Analysis").

where limited invasion of non-native species have been observed (4-5 kg/ha/yr). The maximum annual deposition rates calculated by CALPUFF are more than 100 times below such levels. These results demonstrate that nitrogen deposition from the proposed facility will not result in adverse effects on soils or vegetation resources. The modeled deposition rates reflect a number of conservative assumptions and therefore represent an over-estimation of the actual deposition expected to occur as a result of the project. Even so, the modeled impacts fall far below the levels of concern identified by earlier studies. Based on this nitrogen deposition analysis and other relevant information, the US FWS and EPA have concluded that there will be no significant impacts from nitrogen deposition associated with the facility.[341] The Air District has reviewed the analysis itself, and concurs with the conclusions of FWS and EPA. There will be no significant nitrogen deposition impacts associated with this facility.

The Air District published the results of this nitrogen deposition analysis in the Additional Statement of Basis and invited public comment on it. The District received comments criticizing the analysis on the grounds that it did not examine the project's contribution to nitrogen deposition impacts in the area. The comments stated that the analysis attempts to quantify the East Bay Regional Parks current nitrogen deposition impacts, and does not take into account the impacts that would be caused by the project itself. The comments cited documents from the CEC proceeding for the Metcalf Energy Center to assert that there could be nitrogen deposition concerns related to the proposed Russell City project, and that this deposition would impact an already burdened ecosystem. In response to these further comments, the Air District disagrees that the nitrogen deposition analysis was inadequate. Contrary to the commenters' assertions, the analysis did evaluate the project's contribution to nitrogen deposition in the sensitive areas evaluated. As explained above, the analysis reviewed the project's impacts on nitrogen deposition in these sensitive areas, and found that it would be well below levels where adverse effects would result.[342]

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[341] *See* Letter from G. Rios, EPA Region 9, to B. Young, BAAQMD, re "Section 7 Endangered Species Act Consultation for the Proposed Russell City Energy Center – Hayward, CA" (Jan. 28, 2010) (hereinafter, "EPA ESA Consultation Letter"); Letter from C. Goude, USFWS, to G. Rios, EPA Region 9, re "Endangered Species Informal Consultation on the Proposed Russell City Energy Center Project by Calpine/GE Capital; City of Hayward, Alameda County, CA (Jan. 25, 2010) (hereinafter, "USFWS ESA Consultation Letter"); T. Maurer, USFWS, Technical Assessment: Listed Species and Nitrogen Deposition from the Russell City Energy Center (Jan. 11, 2010) (hereinafter, "Maurer Nitrogen Deposition Assessment").

[342] *See* Letter from Barbara McBride (Calpine) to Anita Lee, PhD (EPA), February 20, 2009, p. 2; Nitrogen Deposition Analysis, *supra* note 340, at p. 3. The Air District also received comments stating that it did not address the potential impacts of ammonia or other toxins on vegetation. The Air District disagrees. The nitrogen deposition analysis specifically included the potential for nitrogen deposition impacts from all potential nitrogen sources, including the facility's ammonia emissions. *See id.,* Nitrogen Deposition Analysis, *supra* note 340, Attachment A, Air Dispersion Modeling Technical Report, *Depositional Modeling Results from the Russell City Energy Center Operation Critical Habitat Areas*, p. 4 (describing AERMOD modeling assumptions to include "100 percent conversion of oxides of nitrogen (NO_x) and ammonia (NH_3) into atmospherically derived nitrogen (ADN)"). The commenter has not cited

The Air District also received comments during the second comment period criticizing the nitrogen deposition analysis by claiming that the analysis wrongly characterized certain areas within the East Bay Regional Parks as forest rather than grassland. These comments alleged that, to model correctly for the impacts to the critical habitats of these species requires a fundamental understanding of what constitutes critical habitat for each species and how nitrogen deposition could potentially have impacts upon that habitat. Because of the deficiencies the comments claimed are inherent in computer modeling of environmental impacts, the comments stated that a full biological opinion was warranted to evaluate impacts to sensitive and threatened species.

The Air District reviewed the analysis in light of these comments, and found that the characterization of the habitats as forest rather than grassland actually resulted in a conservative *over*-estimation of potential deposition in those areas: The maximum amount of deposition in Redwood Regional Park would be slightly reduced to 0.0222 kilograms per hectare per year (kg/ha-yr) (from 0.0223 kg/ha-yr), had the commenter's recommended characterization been used instead; for Garin Regional Park, the maximum amount of deposition would be reduced to 0.3205 kg/ha-hr (from 0.3208 kg/ha-yr).[343] The Air District therefore disagrees that the outcome of the analysis would be any different regardless of how these areas are characterized. Furthermore, the Air District disagrees with the comments that computer modeling in general, or the modeling done for this analysis, are inappropriate methods for reviewing the potential for impacts to soils and vegetation. Computer modeling is a well-accepted method for determining what ambient air quality concentrations could result from emissions of air pollutants from sources such as this one. Those resulting ambient concentrations can then be compared with scientific literature about what ambient levels could lead to adverse impacts. In this manner, the analysis can predict what the "real world" impacts of the project will be. In fact, the analysis intentionally overestimates what the "real world" impacts will be in order to err on the side of conservatism, for example by assuming that all NOx and ammonia emitted will be converted into depositional nitrogen (nitric acid), without considering any of the complex chemical reactions that impact conversion rates. To the extent that these conservative overestimations depart from "real world" conditions, that is fully appropriate for an analysis such as this one.

Finally the Air District also received comments stating that instead of using computer models, actual deposition levels should have been measured within the marshland at Hayward Regional Shoreline to determine whether the proposed project's contribution of nitrogen would bring the total nitrogen load to critical levels involving impact. The comments also alleged that the analysis had failed to consider the importance of deposition to the freshwater ponds in which the tiger salamander breeds. In response to these comments, the Air District disagrees that there is any indication that nitrogen deposition would have any impact to soils or vegetation related to tiger salamander habitat. As noted above, the analysis found that potential deposition will be

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any other specific potential impact that the Air District should have included in the analysis, and the District is not aware of any.

[343] *Compare* Nitrogen Deposition Analysis, *supra* note 340, Attachment A at p. 11, Table 1, *with* Memorandum, Gregory Darvin, Atmospheric Dynamics, Inc., to Barbara McBride, Calpine, "RCEC Nitrogen Deposition Modeling", April 13, 2009.

more than ten times below the lowest threshold at which the scientific literature indicates even limited invasion may occur; and when a less conservative modeling approach was used to better reflect actual atmospheric transformation of combustion emissions into depositional nitrogen, the results showed deposition rates more than one hundred times below that threshold. In light of this evidence, the Air District does not find any reason to conclude that there may be impacts that could adversely impact tiger salamander habitat, and the commenter has not cited any evidence beyond mere speculation. Moreover, the Air District's conclusion is further supported by EPA's Endangered Species Act consultation, in which the U.S. Fish & Wildlife Service concluded that the increase in nitrogen deposition from the facility "appears to be insignificant and in some places of concern (Hayward shoreline), discountable"[344]; and that the facility "is not likely to adversely affect federally listed species . . . ."[345]

For all of these reasons, the Air District disagrees that its soils and vegetation analysis did not adequately address nitrogen deposition issues, and disagrees that there could be a significant adverse impact in this area from the facility's emissions.[346]

<u>Comment XIII.C.4. – Analysis of Potential Impacts to Wildlife:</u>

The Air District also received comments claiming that it did not undertake any analysis of impacts to special status wildlife in the salt marsh, mud flats, and other wetland communities at the Hayward Regional Shoreline. These comments claimed that the Air District has an obligation in the PSD Permit to establish that the facility will have no significant impacts from air emissions to the sensitive wetlands communities adjacent to the shoreline. The comments also claimed that the District failed to evaluate sensitive receptors such as small mammals and birds in the adjacent marsh. The commenter also claimed that the Health Risk Assessment aimed at potential health impacts to humans cannot be extrapolated to small birds and mammals; claimed that impacts on plants in these animals' food supply could harm them; and claimed that some toxics can bioaccumulate.

Response: Although potential impacts to wildlife are very important resource considerations, they are addressed primarily through other regulatory mechanisms such as the Endangered Species Act and CEQA, not through the Federal PSD regulations. Looking specifically at the requirements of the Federal PSD regulations, they address only impacts to soils and vegetation. The Air District has evaluated the potential for such impacts as explained in its soils and vegetation analysis and has found that there will not be any significant soils and vegetation

[344] Maurer Nitrogen Deposition Assessment, *supra* note 341, at p. 4.
[345] USFWS ESA Consultation Letter, *supra* note 341, at p. 1.
[346] One comment also cited concerns about acid rain impacts from the facility, but did not provide any data or information to suggest that any of the PSD-regulated emissions from the facility that the Air District evaluated would contribute to any significant acid rain impacts. The Air District does not believe that there will be any such impacts, as the studies the District used in its soils and vegetation impacts analysis did not show any impacts to soils and vegetation – from acid rain or otherwise – at ambient air quality levels that will result from the facility's emissions. The Air District also notes that EPA and the Fish & Wildlife Service did not find any potential significant adverse acid rain impacts when they conducted their endangered species impacts analysis.

impacts as a result of air emissions from the facility. Soils and vegetation issues can often be related to wildlife issues because soils and vegetation provide habitat and food for wildlife, and so to the extent that there is such a connection here, the Air District's findings of no significant impact on soils and vegetation would support a finding of no significant impacts on wildlife, either.[347] Moreover, EPA Region 9 and the US Fish and Wildlife Service have evaluated the potential for wildlife impacts in more detail and have concluded that the facility is not likely to adversely affect any endangered species, which further supports the Air District's conclusion on this point.[348]

Comment XIII.C.5. – Analysis of Impacts To Aquatic Soils & Vegetation Resources:

The Air District also received comments directed specifically at aquatic resources. The comments suggested that the Air District's analysis has not adequately evaluated the potential for impacts to adjacent or nearby vernal pools, salt marsh areas, and other important soils and vegetation resources in the Hayward Shoreline area. Some comments suggested that heat discharges from the facility could promote the growth of certain marshland and bay-water organisms, which might adversely impact aquatic solids and vegetation and the local ecosystem in general, which could also cause secondary and tertiary impacts upon local air quality. These comments noted that the portion of the San Francisco Bay located near the project site is relatively static in nature and could therefore experience a permanent temperature increase as a result of the facility.

Response: The Air District's soils and vegetation analysis covered all types of soils and vegetation resources, including aquatic vegetation. The analysis specifically identifies a number of aquatic resources, including coastal habitats along the eastern shore of the San Francisco Bay such as salt marshes, brackish/freshwater marshes, brackish sloughs, evaporation ponds, and a creek. The Air District therefore disagrees that its assessment did not appropriately cover

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[347] The Air District also received a communication outside of the comment periods stating that it should take into account the potential for CO_2 concentrations to increase air quality impacts by elevating ozone and particulate matter levels based on the recent research published by Dr. Mark Z. Jacobson (as described earlier in Section XIII.B regarding the $PM_{2.5}$ Source Impact Analysis). This communication cited several animal species that it claimed should be analyzed. This communication is not a formal comment on the record that the Air District is obligated to respond to. But given the public interest in wildlife issues and in the impact of Dr. Jacobson's research paper on this project, the Air District addresses this issue in order to provide the public with the best information possible about the project. As noted above in Section XIII.B., Dr. Jacobson's work is relatively recent and the Air District is wary of incorporating it into its numerical modeling programs for specific projects at this point. But even taking Dr. Jacobson's most conservative and highest predicted impact on ozone and particulate matter levels, the increase in predicted impacts would be only a 0.8% increase in modeled impacts. Given that the modeled concentrations of these pollutants are orders of magnitude below the levels at which adverse soils and vegetation impacts could start to occur, the Air District disagrees that Dr. Jacobson's calculations, even if conservatively applied here, would predict any adverse soils or vegetation impacts or any adverse effect on any species habitat.

[348] *See* EPA ESA Consultation Letter, *supra* note 341; USFWS ESA Consultation Letter, *supra* note 341.

aquatic habitats, vegetation, and other resources. Moreover, although these comments claim that the analysis was inadequate in this respect, they do not point to any specific aquatic resource that they claim would be adversely impacted by the emissions from this facility. The Air District therefore finds nothing in these comments that provides any reason to question the conclusion that the facility will not have any significant adverse impacts on any soils and vegetation resources, including aquatic resources.

With respect to adverse impacts to aquatic soils and vegetation resources from heat discharges from the facility, the facility will actually mitigate any potential warming of the San Francisco Bay from wastewater discharges. This is because the facility will recycle up to 4 million gallons per day of treated wastewater from the City of Hayward's wastewater treatment plant for cooling water, which would otherwise be discharged into the Bay. This wastewater, which the City currently discharges into the Bay, has a temperature of between 68°F and 72 °F, which is warmer than the ambient Bay temperature.[349] By eliminating this discharge to the Bay, the project would actually mitigate any potential Bay warming, not exacerbate it. Moreover, the project itself will not discharge any cooling water or wastewater into the Bay. The project will not use "once-through cooling" – the practice of drawing cooling water from the Bay or other body of water and then discharging the heated effluent back into the same body of water – as has been used at some older power plants in California. Instead, the facility will use cooling water from the City of Hayward's wastewater treatment plant, as noted above, and will use a zero liquid discharge system that evaporates that cooling water and does not discharge anything into the Bay. For these reasons, the Air District disagrees that there will be any negative impacts on warming of the Bay.

Comment XIII.C.6. – Compliance With NAAQS as Evidence of No Adverse Impacts:

The Air District received comments criticizing it for allegedly relying on compliance with the National Ambient Air Quality Standards as evidence that there would be no adverse impacts on soils and vegetation. The commenter claimed that this approach is contradictory to the approach taken with respect to the Metcalf facility.

Response: EPA has recognized that, in general, ambient air that is in compliance with the NAAQS will not have any adverse impacts on soils and vegetation.[350] Moreover, the EAB has held that in many cases, simply relying on the NAAQS (in conjunction with an ESA finding of no impact) is adequate.[351] In accordance with these authorities, this was the approach the District initially took with respect to soils and vegetation for the Federal PSD Permit in the February 7, 2007 Air Quality Impact Analysis the commenters cited (*see* pp. 154-160 of the December 8, 2008 Statement of Basis).

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[349] *See* Daily records from City of Hayward Wastewater Treatment Plant, December 2008 through March 2009.

[350] *See* NSR Workshop Manual at pp. D.4-D.5. ("For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects.").

[351] *See In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 130 n. 33 (EAB 1997).

That said, in many cases additional investigation and analysis is warranted to ensure that there would be no soils and vegetation impacts at levels even below the NAAQS. That is what the Air District did in this case upon remand when members of the public raised concerns about soils and vegetation impacts. To that end, the Air District prepared a very detailed analysis of potential soils and vegetation impacts using studies that examined ambient air pollution levels at which plant impacts can be observed.[352] This analysis showed that the facility will not cause any significant adverse impacts to soils and vegetation. The Air District therefore agrees with this comment to the extent that the comment suggests that further analysis beyond simply looking to NAAQS compliance is warranted here. The Air District disagrees with the comment, however, to the extent that it suggests that the facility will have adverse soils and vegetation impacts or that the Air District's analysis in this respect was somehow deficient.

Comment XIII.C.7. – Air Quality Impact Analysis Public Review Process:

The Air District also received comments complaining about the process that was used to develop and air quality impact analysis, and in particular the soils and vegetation analysis. The commenter claimed that no public meeting was held to review the air quality impacts to the sensitive wetlands at the Hayward Regional Shoreline, in contrast to what was provided for the Metcalf Energy Center, another power plant project. The comments also claimed that there has never been an analysis of the air quality impacts to sensitive resources on the Hayward Shoreline, and no mitigation of the project's emissions, because the CEC refused to re-open its environmental review and the District has not undertaken one.

Response: The Air District disagrees with these comments. The Air District provided a full public review process on its soils and vegetation analysis as part of the public review process for the entire permit. The Air District also held a public hearing in Hayward as a part of this public review process. This process was at least as robust, if not more robust, than the process that the Air District provided for the Federal PSD Permit for the Metcalf Energy Center. With respect to the CEC's environmental review, the Air District disagrees that the analysis failed to address sensitive resources or to provide mitigation for air quality impacts. Complaints about the CEC's process, however, should be directed to that agency and are not part of the PSD permit analysis.

Comment XIII.C.8. – Use of Soils & Vegetation Analysis Guidance Documents:

The Air District also received comments claiming that its soils and vegetation analysis is not consistent with guidance documents from several agencies on how to assess soils and vegetation impacts. These comments suggested that the Air District should redo its analysis consistent with current guidance.

Response: The Air District followed the approach suggested by the most current and authoritative EPA guidance that it is aware of, the 1990 NSR Workshop Manual. While not binding on the Air District, the NSR Workshop Manual has been widely accepted among permitting agencies as providing a sound method for addressing PSD issues, and its use has been approved by the Environmental Appeals Board. The Air District therefore disagrees that it has not properly followed appropriate guidance in conducting its soils and vegetation analysis. To

[352] *See* Statement of Basis, Appendix C, Soils & Vegetation Analysis, pp. 90-93; *see also* Additional Statement of Basis at pp. 89-91.

the extent that anything in any of the guidance documents referred to in the comments is inconsistent with the Air District's methodologies, the Air District declines to follow that guidance and finds it more appropriate to use the methodology established in the NSR Workshop Manual.

Comment XIII.C.9. – Use of 1980 EPA Screening Procedure:

The Air District received comments criticizing its use of EPA's 1980 screening procedure for soils and vegetation impacts.

Response: The Air District agrees that a soils and vegetation impacts analysis should not be based only on passing a EPA 1980 screening procedure review. A complete soils and vegetation analysis should include site-specific information about the specific species present near the project location; an evaluation of the sensitivities of such species to air pollutant exposure; an assessment of the ambient air pollutant concentrations that the facility would cause; and then a comparison of modeled concentrations against the concentrations at which impacts might occur in the species in the vicinity of the project.[353] The Air District did exactly that here, and found that pollutant concentrations resulting from the facility would be well below levels at which impacts might be seen. Beyond this analysis, however, comparison with the EPA's 1980 screening procedure levels is not inappropriate as an additional tool to ensure that there will be no significant impacts. The Air District conducted this screening review for informational purposes to determine that the facility will not have any significant impacts under this methodology as well.[354]

Comment XIII.C.10. – Currentness of Reference Materials Relied On:

The Air District also received comments claiming that it should use current reference material for the analysis of potential impacts on soils and vegetation. These comments questioned some of the sources that the Air District relied on in its analysis based on their age.

Response: The Air District disagrees that the sources of information it used are unreliable or inaccurate. The passage of time alone does not make information unreliable, and the Air District is not aware of any new information that would suggest that is analyses were flawed. These comments have not pointed to any area in which the Air District's analysis was defective based

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[353] *See* NSR Workshop Manual, pp. D.4-D.5, D.11-D.12.

[354] Some comments also questioned why the Air District used 1-hour average concentrations for its comparison with the 4-hour average NO_2 screening threshold (*see* Table VI of the Air Quality Impact Assessment, on p. 93 of the initial Statement of Basis). The 4-hour averaging period listed for the NO_2 screening concentration (as well as the 8-hour and 1-month averaging periods) is set forth in the EPA screening procedure. The Air District did not have modeling results based on a 4-hour averaging time period, so it used the 1-hour results that it did have from its modeling. The Air District assumed that the maximum 1-hour average results would occur in each of the four hours covered by the 4-hour averaging period for purposes of the comparison with the screening levels. Note that this is a conservative assumption because it would be highly unlikely for the maximum predicted 1-hour average concentrations to occur in each of four successive hours. Nevertheless, despite this conservatism, the comparison still shows that the facility's impacts will be more than 10 times less that the 4-hour screening concentration.

on the sources of information the Air District used, nor have they provided any reason why the analysis should have reached a different conclusion.

Comment XIII.C.11. – Identification of the Facility's Proximity to Specific Soils & Vegetation Resource Locations:

The Air District received comments questioning whether Don Edwards San Francisco Bay National Wildlife Refuge and the South Bay Salt Pond restoration project are within 1 mile of project (although the comments did not assert that such proximity could affect any aspect of the Federal PSD Permit process). These comments also questioned whether the California Department of Fish & Game ("DFG"), the U.S. Fish & Wildlife Service ("FWS"), and Coastal Conservancy should have been notified about the proximity of the proposed facility to the restoration project. The commenters also asked how far it is from the project location to the San Francisco Bay, and whether the "on-site waterway" is affected by tides (but again not explaining how these questions could affect the permit).

Response: These comments do not raise any issues that affect the outcome of the soils and vegetation analysis. The Air District adequately surveyed the soils and vegetation conditions in the vicinity of the project location and considered the potential for adverse impacts from the facility's emissions. Moreover, the Air District properly notified the public and all required agencies of its permit proceeding. These comments do not provide any reason why any element of the soils and vegetation analysis was inadequate, and the Air District is not aware of any.

Comment XIII.C.12. – Analysis of Potential for Impacts to Lichens:

The Air District received comments suggested that the District should include lichens in its soils & vegetation analysis. The comments specifically noted a screening level for SO_2 impacts of 13 $\mu g/m^3$ based upon a study of certain types of Alaska lichens.

Response: No biological survey has identified the presence of lichens as a species of concern, and the comments did not point to any evidence or studies that do so either. Moreover, to the extent that there are any lichens in the vicinity of the project, it is unlikely that the project's emissions would have any significant impact on them given the findings of the Air District's analysis showing that the facility's emissions will be orders of magnitude less than the levels at which impacts to plants could occur. (The Air District notes that the commenters quote a study finding that "visible injury symptoms occur at lower doses in crops and conifers than in lichens.") The Air District therefore has no reason to believe that there could be any significant impact to lichens from the proposed facility. With respect to a 13 $\mu g/m^3$ screening threshold for SO_2 impacts, this facility will not have SO_2 emissions above the PSD significance threshold and no soils and vegetation analysis for SO_2 emissions is required.

Comment XIII.C.13. – Photosynthetic Generation of Oxygen By Plants:

The Air District also received a comment stating in its initial Statement of Basis the Air District stated that plants metabolize and produce carbon monoxide, whereas in fact they actually produce oxygen.

Response: In response, the Air District agrees that plants produce oxygen, but they also can metabolize and produce carbon monoxide in addition to their other metabolic processes.[355] But none of the Air District's analysis was based on a finding that plants produce carbon monoxide, so this issue is ultimately moot.

D. "Associated Growth" And "Secondary Emissions" Analyses

The Air District also received comments questioning its assessment of secondary emissions and its associated growth analysis performed as part of the AQIA, which the Air District addressed at pages 16 and 93-94 of the Statement of Basis and additionally at pages 91-92 of the Additional Statement of Basis. The Air District responds to these comments here.

As a general introduction regarding these comments, the Air District notes that there are two independent concepts at issue. One is "secondary emissions" associated with the facility, which are emissions that are not from the facility itself but arise from some other related source that would not be constructed or operated but for construction of the facility under review. Secondary emissions do not include emissions from any facility that would be constructed for some reason other than construction of the facility under review. Moreover, secondary emissions include only emissions from a related facility that are (i) specific, (ii) well-defined, (iii) quantifiable, and (iv) impact the same general area as the stationary source. A paradigm example would be emissions from a quarry owned by a cement company that supplies aggregate to a cement plant. If the company needs to double the size of its quarry operation in order to double the capacity of its cement plant, the increased emissions from the quarry would be "secondary emissions" for purposes of PSD review. If the cement plant expansion triggered PSD review, the PSD review would have to consider the increased quarry emissions as "secondary emissions" directly resulting from the increased capacity of the cement plant.[356] Only specific emissions such as this that are directly associated with the facility under review are considered as "secondary emissions". Notably, mobile source emissions are generally excluded from "secondary emissions" subject to PSD consideration.

The other concept involved here is "associated growth". The PSD regulations require that permitting agencies include any general commercial, residential, industrial or other growth associated with the source in the Additional Impacts Analysis.[357] Such growth includes expansion of existing infrastructure necessary to support the operation of the facility under review, such as additional growth in industries necessary to provide goods and services the facility will need to operate (*e.g.*, the production of raw materials, the development of maintenance facilities, *etc.*), additional growth in residential development and related infrastructure (*e.g.*, schools, shopping facilities, *etc.*), and other similar types of support

[355] Air Quality Criteria for Carbon Monoxide, EPA 600/P-99/001F June 2000, page 1-1 (available at www.epa.gov/NCEA/pdfs/coaqcd.pdf).
[356] *See* 40 C.F.R. § 52.21(b)(18) (regulatory definition of "secondary emissions"); NSR Workshop Manual at § A.II.B.4, pp. A.16-18, (discussing the "secondary emissions" requirements).
[357] *See* 40 C.F.R. § 52.21(o)(1), (2).

infrastructure. Again, mobile source emissions such as emissions from cars and trucks are excluded from this review.[358]

With these general concepts in mind, the Air District addresses the specific comments it has received in these areas.

<u>Comment XIII.D.1. – Emissions Associated With Project Workforce:</u>
The Air District received comments questioning whether there might be emissions from associated growth related to temporary and permanent workers at the site, for example in the form of transportation emissions generated through commuting.

Response: With respect to emissions from the workforce that will be associated with the project, the Air District disagrees that their will be any secondary emissions or associated growth resulting from the need for workers at the facility, as those terms are defined for purposes of the PSD permitting analyses. The comments have not identified any new facilities that will need to be constructed in addition to the proposed facility in order to accommodate workers at the site, and certainly have not pointed to any specific, well-defined, and quantifiable emissions that would occur as a direct result of this facility. Furthermore, the need for workers for the project will not cause any significant associated growth because they will come from the existing workforce, which is more than adequate to meet the facility's needs. The comments did not suggest that this conclusion that the facility's jobs will adequately be supplied from Bay Area's workforce was incorrect. As the project will not cause any significant increase in the size of the workforce in the Bay Area, there will not be any need for any significant expansion of associated infrastructure such as housing or other infrastructure that would constitute "associated growth". To the extent that workers will have to commute to the facility to do their jobs, which may entail transportation emissions, mobile source emissions associate with employee commuting are not generally included in a source impact analysis, as noted above. Furthermore, even if transportation emissions were subject to review, there will not be any significant *increase* in emissions from the project since it will draw workers from the existing workforce, who are already living and driving in the Bay Area.

<u>Comment XIII.D.2. – Potential for New Growth and Development That May Use Electricity From The Facility:</u>
The Air District also received comments suggesting that the new electrical generating capability provided by the facility may cause associated growth and the development, and that the District should take into account the air emissions from such growth. The comments similarly claimed that the District did not properly take into account associated negative growth in sustainable electrical generation.

Response: With respect to the new electrical generating capacity that the project will provide, it is speculative whether this new capacity will be a cause of any significant growth in the region. Some of it may be used to take the place of older generating capacity that is being taken off-line, and even if it does provide some overall expansion of the region's total electric generating capacity there is no indication that this would cause any new development. It is unlikely that any

[358] *See generally* NSR Workshop Manual at § D.II.A., pp. D.3.-D.4.

new growth or development will occur simply because of the existence of excess electrical generating capacity, as opposed to some other independent reason.

The Air District published this further analysis in the Additional Statement of Basis. The Air District subsequently received comments during the second comment period that questioned the District's statements that it would be speculative to predict that the electrical generating capacity that would be provided by the Russell City facility would cause new induced growth or development. These further comments claimed that it is clear that areas without electricity do not tend to grow and that areas with excess capacity tend to grow. The commenters stated that the Air District should therefore conduct a growth analysis to take into account growth that would be induced the power provided by the new facility.

In response to these further comments, the Air District reiterates that speculation regarding whether the facility's electrical generating capacity will directly cause any new growth development does not constitute "secondary emissions" or "associated growth" as those concepts are used in the PSD permitting analysis. Such speculation does not identify any specific new facilities that would not be constructed but for the construction of this power plant. Moreover, generalized speculation that new growth may occur in the future that will use electricity from this facility does not identify any specific, well-defined, and quantifiable emissions increases in the vicinity of this facility of the type that are considered "secondary emissions". And such speculation does not identify any new infrastructure that would be required to serve the facility of the type that could be considered "associated growth". For all of these reasons, the Air District continues to disagree with the commenters' assertions that there may be new growth or development that may use electric power generated by this facility; or that the Air District needs to conduct an analysis of any potential for new growth or potential air quality impacts that could be associated with it.

<u>Comment XIII.D.3. – Wastewater Treatment Plant Expansion:</u>

The Air District also received comments claiming that the project has already generated secondary growth in the form of an expanded local water treatment plant, the capacity of which was increased to provide cooling water for the project.[359]

Response: This comment appears to be based on a misconception regarding the proposed facility's relationship with the City of Hayward's wastewater treatment plant. The proposed facility has been designed to handle wastewater from the treatment plant and use it as cooling water. The wastewater treatment plant will not handle wastewater from the proposed facility. This will be an environmentally beneficial aspect of the facility in that it will obviate the need for the City of Hayward to discharge its wastewater into the Bay (although this aspect of the project has no direct relationship with air quality). The project will require a new tertiary treatment

[359] These comments also cited the Eastshore project, an unrelated power plant project that was not approved by the CEC, as evidence for the proposition that once a high impact project has been approved for an area, it paves the way for other similar projects. The Air District disagrees that this speculation that additional facilities may be located near this project provides any reason to conclude that there may be specific secondary emissions or associated growth that the Air District needs to analyze regarding this PSD permit.

plant to treat the wastewater from the wastewater treatment plant in order to make it clean enough to use in the facility's cooling system (which is a direct part of the facility itself, not construction of a secondary facility), but it will not involve any expansion to the capacity of the wastewater treatment plant. The District is unaware of any other relevant changes that have been made to the wastewater treatment plant, and in particular of any changes that may impact air quality. The Air District published this explanation in the Additional Statement of Basis and invited members of the public to comment further if they were aware of any increases in air emissions from any expansion with respect to the wastewater treatment plant as a result of this project, but did not receive any further comments on this issue during the second comment period. For all of these reasons, the Air District disagrees that there will be any secondary emissions or associated growth with respect to the wastewater treatment plant that the District needs to evaluate in connection with this Federal PSD permit.

XIV. HEALTH RISK ASSESSMENT ISSUES

The Air District also received several comments regarding the Health Risk Assessment it prepared for the facility. The Health Risk Assessment is performed as a requirement of the Air District's state-law regulations, and it is therefore not directly a part of the PSD Permit evaluation, as the Environmental Appeals Board explained in its Remand Order for this permit (*see* Slip Op. at p. 41). The Air District is responding to these comments here, however, for two reasons. First, the Air District considers a facility's potential for health risks to be an important topic of public interest that it wants to inform the public about. Second, the Air District is also responding to the extent that these issues may be tangentially related to PSD issues in that the Air District has relied on an assessment of health risks in connection with PSD-related analyses such as considerations of ancillary environmental effects of various BACT control alternatives and considerations of potential impacts to Environmental Justice communities. The Air District therefore presents these responses to the comments it received on its Health Risk Assessment.

Comment XIV.1. – Methodology Used in Health Risk Assessment:

The Air District received comments questioning the Health Risk Assessment methodology it used, and in particular whether it is appropriate for use in federal PSD Permitting. Some comments suggested that the Health Risk Assessment methodology may not take into account segments of the population with heightened sensitivities. One comment also questioned why health impacts with a hazard index of less than 1 are not significant. Another comment criticized the District's methodology for assessing risk with respect to morbidity, and claimed that the District should consider mortality instead.

Response: In response to these comments, the Air District notes at the outset that the PSD permitting requirements do not directly require a Health Risk Assessment to be performed at all. *See* 40 C.F.R. section 52.21. PSD permitting does tangentially involve the District's Health Risk Assessment in areas like the BACT comparison of alternative control technologies, which can involve an assessment of collateral environmental impacts such as toxics risk, but EPA does not specify any specific methodology for conducting such an assessment. Instead, EPA allows permitting agencies to use whatever methodology is most appropriate.[360] The Air District uses the methodology developed by California's Office of Environmental Health Hazard Assessment ("OEHHA"), which is highly appropriate for this purpose and is designed to account for sensitive populations.[361]

With respect to why a hazard index of less than one is not significant, a hazard index below one means that the toxic exposure is less than the "Reference Exposure Level", which is a level developed by health professionals as an indicator of potential adverse health impacts. The

[360] *See In re J&L Specialty Products Corp.*, 5 E.A.D. 31, 81 (EAB 1994) ("It is entirely reasonable for the Region, in the exercise of its discretion, to give credence to State policy and guidance documents in effect under State law at the time of permit issuance.").

[361] In particular, the issue of including acrolein in the Health Risk Assessment was raised in connection with the OEHHA methodology the Air District used. The EAB Remand Order in this case specifically directed that this is not an issue that needs to be considered in the PSD permitting analysis (*see* Remand Order at p. 41).

hazard index is the sum of the individual hazard quotients for toxic air contaminants identified as affecting the same target organ or organ systems. A hazard quotient is the ratio of the estimated exposure level to the Reference Exposure Level, which is the concentration level at or below which no adverse health effects are anticipated. An exposure below the Reference Exposure Level means that no adverse health effects are anticipated for the exposure duration involved. The Hazard Index measures exposure relative to this Reference Exposure Level; a Hazard Index of less than 1 means that the exposure will be less than the Reference Exposure Level and thus protective of public health.

With respect to considering morbidity instead of mortality in assessing the level of risk, morbidity is an appropriate measure for health risk assessment purposes. Looking at morbidity is actually more conservative in that it captures all potential health problems, not just those that are fatal. That is, morbidity encompasses all potential health effects that could arise from toxic exposures, whereas mortality encompasses only those health effects that might cause death, which is a smaller subset of exposures. The Air District therefore disagrees that the morbidity approach is inappropriate for a health risk analysis.

Comment XIV.2. – Exposure Assumptions for Chronic Risk Assessment:

The Air District received comments stating that the chronic exposure modeling was based on the assumption that chronic exposure to toxic compounds will last one year, which they claimed is inappropriate for a power plant that will likely be in operation for a longer time period.

Response: The Air District agrees that the chronic exposure modeling must assume a long-term exposure scenario, not just one year of exposure. This comment has apparently misunderstood how the Air District conducts its non-carcinogenic chronic health risk assessment, however. For chronic risks, the Health Risk Assessment looks at the annual exposure rate for the maximally exposed individual, and then assumes that the individual will be exposed to this maximum annual exposure rate for the entire year over every year of an assumed 70-year life span. The Health Risk Assessment therefore appropriately captures lifetime risk; it does not assume that exposure occurs for one year and then stops.[362] The Air District explained this situation in the Additional Statement of Basis, and did not receive any further comments on this issue during the second comment period.

Comment XIV.3. – Assessment of Cumulative Risks From Project In Conjunction With Other Sources of Toxic Risk:

The Air District received several comments stating that its Health Risk Assessment did not consider cumulative or synergistic effects of exposure to all sources of air pollution including both the proposed facility and other existing sources in the area.

Response: The Air District's Health Risk Assessment methodology does not include an assessment of cumulative risk from project plus existing background sources for several reasons. First, where level of risk from a project is found to be so low that it is below the HRA significance thresholds, the project is not expected to make more than a *de minimis* contribution

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[362] *See* Memorandum from Glen Long to Weyman Lee, February 28, 2007, *re* Results of Health Risk Screening Analysis for Russell City Energy Center, at p. 1.

to any cumulative risk. Emissions below these low threshold levels will simply not make any significant additional contribution to the overall cumulative risk, and assessing the facility's addition to the overall cumulative risk burden would therefore add relatively little to the understanding of the cumulative concern. Moreover, undertaking a risk assessment encompassing all emission sources in the region of the facility would require resources that do not exist at this time. There are significant technical difficulties associated with completing a neighborhood-scale cumulative HRA, which are largely related to incompleteness of data (*e.g.*, spatial and temporal emission patterns) needed to estimate exposures and health risks, and to ascertain source contributions. Furthermore, unlike for criteria air pollutants, no standards have been established for health risks associated with cumulative exposure to TACs emitted from all sources, and so it would be difficult to assess at what level additional cumulative impacts would become significant. And finally, cumulative environmental impacts must be assessed for any project in California under CEQA, and so to the extent that cumulative toxic risks have the potential to be significant they can be addressed in that context. For all of these reasons, the Air District's Health Risk Assessment procedures – and the OEHHA methodology on which the District's procedures are based – do not provide for a cumulative analysis that takes into account the facility's impacts in conjunction with existing local background sources. The procedures rely instead on the HRA significance levels to prevent significant additional contributions to cumulative risks.

Comment XIV.4. – Health Risk Assessment for Ammonia Emissions:

Commenters stated that ammonia emissions will be up to 15.2 lb/hr, which they claimed exceeds the acute screening trigger level of 7.1 lb/hr. The commenters claimed that the District should therefore thoroughly analyze potential health impacts from the ammonia emissions.

Response: The comments are correct that ammonia emissions would be above the Health Risk Assessment screening level, and accordingly the Health Risk Assessment did in fact take ammonia emissions into account.[363] The Health Risk Assessment found that the risk from all toxics, including ammonia, was less than significant.

Comment XIV.5. – Legionnaire's Disease:

Commenters suggested that the wet cooling system could involve a risk of causing Legionnaire's disease, and claimed that this potential health risk should be investigated further as part of the Health Risk Analysis. The commenters implied that the use of recycled water from the City of Hayward's wastewater treatment plant could increase the risk of Legionnaire's disease.

Response: The Air District notes that its expertise as a public health agency is primarily in the area of chemical air pollutant and the health problems they can cause, not in medical pathogens. For this reason, the Air District does not address medical concerns such as issues related to Legionnaire's disease in its Health Risk Assessment. To the extent that the proposed project may raise concerns about Legionnaire's disease, those concerns should appropriately be addressed in the broader environmental review context through the Energy Commission's CEQA-equivalent process. Nevertheless, in response to repeated requests that the Air District itself should evaluate the potential for risks regarding Legionnaire's disease, the Air District has

[363] *See id.*

investigated this issue in detail. The Air District has found that there will be not be any significant risk of Legionnaire's disease from the cooling tower emissions because of several safeguards that the project will incorporate. First, the facility will be required under Section 60306 of Title 22 of the California Code of Regulations and by the conditions of its CEC license to treat the cooling tower water with chlorine or other biocide to prevent the growth of the Legionnella bacterium and other micro-organisms. The facility will be required to establish a Cooling Water Management Plan incorporating this requirement and following the CEC's "Cooling Water Management Program Guidelines" or with the Cooling Technology Institute's "Best Practices for Control of Legionnella" guidelines. The facility will also be required to sample and test for the presence of Legionella bacteria at least every six months.[364] The cooling tower will also use a high-efficiency drift eliminators to minimize risks. The Occupational Safety and Health Administration has recognized these measures as appropriately addressing the potential for Legionnaire's disease risks associated with cooling systems of this type.[365] With all of these safeguards in place, the Air District has concluded that there will not be any significant risk of Legionnaire's disease outbreaks from this facility.

<u>Comment XIV.6. – Including Startup Emissions In Health Risk Assessment:</u>

The Air District also received comments expressing a concern that Toxic Air Contaminant ("TAC") emissions may be higher during startups. These comments stated that the Air District should assess TAC startup emissions and take them into account in its Health Risk Assessment for the facility.

Response: The Air District has considered Toxic Air Contaminants associated with startups in response to this comment. The Air District obtained information on TAC emissions rates from a source test conducted at the Palomar Energy Center facility during startup operations.[366] For TACs that were not measured during that source test, the Air District used the full values of the California Air Toxic Emission Factors ("CATEF") emission factors published by the Air Resources Board, with the assumption that there would be no reduction in emissions as a result of abatement equipment. The Air District then conducted a revised Health Risk Analysis assuming that the facility would operate at these higher startup levels continuously.[367] This is obviously a highly conservative assumption, as the facility will not operate in startup mode continuously, but the Air District used the assumption anyway to ensure that the analysis was adequate as a risk screening measure. Using these conservative assumptions, the Health Risk Assessment showed that the highest cancer risk would be 0.72 in one million, the highest chronic non-cancer health risk would be a Hazard Index of 0.0182, and the highest acute non-cancer

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[364] 2007 Energy Commission Decision, *supra* note 16, at p. 112-13, Conditions of Certification PUBLIC HEALTH-1.

[365] *See* OSHA Technical Manual § III, ch. 7(V).

[366] See San Diego Air Pollution Control District, *Carlsbad Energy Center Rule 1200 Health Risk Assessment Report* (Aug. 3, 2009), Appendix B to Carlsbad Energy Center FDOC, *supra* note 134, at pp. 8-10 (summarizing toxics emission factors based on source test at the Palomar Energy Center).

[367] The emission levels used are summarized in a Memorandum from Weyman Lee to Glen Long, dated October 2, 2009 (and as further documented in the attachment "Supplemental HRA for cold startup operations).

health risk would be 0.0415.[368] All of these risk levels are less than significant, and so the Air District concludes that even if the facility were to operate full-time in startup mode, the TAC emissions would not cause a significant health risk. This conclusion is the same as the conclusion that the Air District reached in the Statement of Basis and Additional Statement of Basis.

Comment XIV.7. – Health Risk Assessment for Aircraft Pilots and Passengers:

The Air District received comments claiming that the Health Risk Assessment should take into account potential health risks to pilots and passengers flying in the vicinity of the proposed facility.

Response: In response to these comments, the Air District has conducted an additional health risk assessment using an air dispersion model to determine emissions impact above ground level (*i.e.*, using a "flagpole receptor"). The maximum potential hazardous air pollutants emission rates were used. Flagpole receptor is defined where persons (pilots and passengers) may be exposed to concentrations above ground level (flight area) of a particular compound or substance. The locations are not necessarily a residence or a location where people actually exist; it may be any offsite above ground level where a person could potentially be present.

The proposed project will have two stacks each having a height of 145 feet above the ground level. The acute hazard index was calculated to be 0.52.[369] A value below 1.0 means that the exposure would not cause any adverse health effects. The location of the maximum acute hazard index is very close to the RCEC stacks and is based on one-hour exposure level. This is most likely a conservative assumption, as it is unlikely that that pilots and/or passengers would remain at this location in the airspace for a continuous hour and be exposed to the full extent assumed in the District's analysis.

The Air District received a comment during the second comment period that aircraft could be exposed to facility exhaust for extended periods of time if they have to circle the airport or if they repeat takeoffs, landings or other maneuvers multiple times for practice or training purposes. But even in this situation, with repeated passes through the facility's exhaust stream, the aircraft would still not be within the stream continuously and so the exposure assumptions would still be overly conservative. And even if for some reason an aircraft did remain directly within the exhaust stream for a continuous hour, the acute hazard index was well below 1.0, demonstrating that even continuous exposure during that time would not cause any risk of adverse health effects. The Air District also received a comment during the second comment

[368] *See* Memorandum from Glen Long to Weyman Lee, December 14, 2009.

[369] *See* email memorandum from Glen Long, BAAQMD, to Bob Nishimura, BAAQMD, March 12, 2009. Comments noted a discrepancy between a statement by the District in the Additional Statement of Basis that the project will have 150-foot tall stacks and the CEC's documentation stating that the stacks will be 145 feet tall. These comments are correct that in the discussion of Health Risk Analysis issues in the Additional Statement of Basis, the Air District mis-stated the stack height as 150 feet (*see* Additional Statement of Basis at p. 95). The correct height, and the height that was used in all the modeling analyses for this facility, is 145 feet. (*See, e.g.*, Proposed PSD Permit, condition no. 38, Additional Statement of Basis, p. 109.)

period that the Health Risk Assessment should use a lower exposure threshold for aircraft pilots, crews and passengers than for the general population, given the nature of aircraft operation. The Air District disagrees with this comment. The Reference Exposure Levels on which the Health Risk Assessment analysis is based are already designed to take into account sensitive populations (with an appropriate margin of safety), and there is no reason to conclude that pilots, aircrews, or passengers would experience a risk of adverse health effects where the hazard index is well below 1.0. The Air District therefore disagrees with the suggestions that its Health Risk Assessment with respect to aircraft operations was not appropriate.

Comment XIV.8. – Health Impacts of Fine Particulate Matter:

The Air District received comments citing recent developments in the understanding of the health impacts of fine particulate matter. These comments suggested that the Air District should consider fine particulate matter in its Health Risk Assessment. These comments also claimed that the HRA approach uses a PM_{10} 'surrogate' method to assess risks from fine particulate matter exposure and does not specifically address $PM_{2.5}$ exposure issues.

Response: The District has considered adding fine particulate matter in our permitting procedures. In addition, OEHHA is planning to develop new procedures to address fine particulate matter and to incorporate them into its health risk assessment guidelines that are used by air districts. The District intends to participate in the public process to develop future updates to the risk assessment guidelines and procedures. These guidelines have not been developed at this stage, however, and so the Air District does not have the appropriate tools to include fine particulate matter in its formal Health Risk Assessment. The Air District has addressed fine particulate matter in its PSD Air Quality Impact analysis, however, as detailed above. That analysis found that emissions from the proposed facility would not have any significant contribution to any fine particulate matter pollution in violation of the stringent new National Ambient Air Quality Standards, which are health-protective standards established by EPA.

The Air District discussed this situation in the Additional Statement of Basis and solicited further comments on this issue. In response to the District's statement that it has not yet developed tools to include fine particulate matter in its formal Health Risk Assessment procedures, commenters stated during the second comment period that the Air District should develop such tools before it processes this permit or should rely on the expertise of someone else who has developed the tools. In response to this further comment, the Air District disagrees that air quality permitting decisions need to be delayed while scientific understanding of $PM_{2.5}$ issues is developing. Recent advances in scientific understanding regarding the health impacts of $PM_{2.5}$ are already reflected in EPA's recently-updated NAAQS, and in the Clean Air Act's permitting approaches for ensuring that the ambient air meets the NAAQS. Those permitting requirements – such as the BACT requirement and offsets for major new sources and modifications – as well as the applicable planning requirements that will require further regulatory initiatives going forward – will ensure that the NAAQS are achieved in the Bay Area, even with the permitting of new facilities in the meantime. Moreover, science is always developing and there are always current concerns that are under investigation for which further information and regulatory tools may become available in the future. It would not be reasonable from a policy perspective to put all new development on hold because new scientific understanding is in the process of being developed into enhanced regulatory approaches, as that will always be the case. For all of these reasons, the Air District disagrees with the comments that it should put off issuing permits until such time as $PM_{2.5}$ can be included in its formal Health Risk Assessment methodology. This is especially true in the case of this facility, which is a natural-gas-fired facility and will emit relatively small amounts of particulate matter.

Comment XIV.9. – Consideration of CO_2 Emissions in Assessing Health Risks:
The Air District received comments stating that the District should take into account the potential for increases in PM and ozone concentrations due to CO_2 emissions when considering the potential health impacts of this facility. These comments were based on the recent research published by Mark Z. Jacobson, which the Air District discussed in Section XIII.B.9. above in connection with its $PM_{2.5}$ Source Impact Analysis. These comments stated that CO_2 emissions from the project will cause increases in death, morbidity, and emergency room visits in addition to the health risks that the District has already analyzed in connection with the proposed permit.

Response: As discussed above in Response to Comment XIII.B.9., regarding impacts of CO_2 concentrations on particulate matter formation, the Air District is following Dr. Jacobson's research but is hesitant to depart from currently-accepted Health Risk Assessment methodologies at this point. However, in response to these comments and the public concerns expressed about the potential for health risks from this facility, the Air District undertook an assessment of what difference it might make in the outcome of the Health Risk Assessment if Dr. Jacobson's findings were incorporated. Dr. Jacobson published estimates of the additional health impacts from all anthropogenic sources of CO_2 based on the Los Angeles area, California and a whole, and for the entire United States. Dr. Jacobson's estimates are summarized in Table 8 below. For the most part, these estimates show that the total impact from all anthropogenic CO_2 sources will be an increase of less than one percent (with a few outliers showing a decrease in the impact or an increase of more than one percent). These are relatively small changes.

Table 8: Summary of Data Published by Dr. Mark Z. Jacobson Regarding Changes In Air Pollution-Related Health Impacts Due To The Effect of CO_2 Emissions[370]

	California			Los Angeles Area			United States		
	Base Case	Change from CO_2	% Change	Base Case	Change from CO_2	% Change	Base Case	Change from CO_2	% Change
Cancer:									
USEPA	44.1	+0.016	+0.036%	22.0	+0.28	+1.27%	573	+6.9	+1.20%
OEHHA	54.4	-0.038	-0.070%	37.8	+0.39	+1.03%	561	+11.8	+2.10%
Ozone:									
Deaths (high)	6860	+19	+0.28%	2140	+20	+0.93%	52,300	+245	+0.47%
Deaths (med.)	4600	+13	+0.28%	1430	+14	+0.98%	35,100	+166	+0.47%
Deaths (low)	2300	+6	+0.26%	718	+7	+0.97%	17,620	+85	+0.48%
Hosp.	26,300	+65	+0.25%	8270	+75	+0.91%	200,000	+867	+0.43%
ER Visits	23,200	+56	+0.24%	7320	+66	+0.90%	175,000	+721	+0.41%
Particulate Matter:									
Deaths (high)	42,000	+60	+0.14%	16,220	+147	+0.906%	44,800*	+810	+1.8%*
Deaths (med.)	22,500	+39	+0.17%	8500	+81	+0.095%	169,000*	+607	+0.36%*
Deaths (low)	5900	+13	+0.22%	2200	+22	+1%	316,000*	+201	+0.064*

Notes: USEPA = Cancer rates calculated using EPA's methodologies.
OEHHA = Cancer rates calculated using OEHHA methodologies
Deaths (high/med./low) = Predicted additional deaths from increased air pollution formation associated with increased CO_2, based on three varied assumptions of the impact on additional mortality per unit increase in air pollutant concentrations.
Hosp. = Predicted additional hospitalizations
ER Visits = Predicted additional emergency room visits.
*Note that the US particulate matter death numbers are highly suspect because the high estimate is the lowest number and the low estimate is the highest number. In addition, it seems highly unlikely that there could be 42,000 particulate-related deaths in California but only an additional 2,800 throughout the rest of the entire United States. This apparent oversight may be the result of the fact that Dr. Jacobson's paper has not at this point been peer-reviewed.

Moreover, these are the estimated impacts predicted for all anthropogenic CO_2 sources. If one were to break out only this facility's CO_2 emissions from all other anthropogenic sources, the impacts would be even lower. The Air District therefore disagrees that Dr. Jacobson's research gives any reason to revisit the Air District's conclusion that the air emissions from this facility will not have any significant health impacts.

370 Source: Jacobson Paper, *supra* note 35, at p. 12, Figure.

XV. ENVIRONMENTAL JUSTICE ISSUES

Comment XV.1. – Demographics of Project Location:

The Air District received several comments regarding environmental justice issues. Comments stated that there are areas near the proposed facility with low-income and minority residents, employees and students, and claimed that the project disparately places environmental burdens on them. Some comments also referenced an Environmental Justice analysis undertaken by the CEC that found that the area is 'majority-minority'.

Response: The Air District is aware of the CEC's analysis regarding the demographic makeup in areas near the project site, and acknowledges the other information cited by the commenters regarding the demographic makeup of the area surrounding the proposed facility. The Air District does not disagree with this assessment. But the Air District's conclusion that there will be no disproportionate adverse impacts on any environmental justice community was not based on an assumption that there are no environmental justice communities near the project site. To the contrary, it was based on the District's assessment that there will be no significant adverse impacts to any community, regardless of demographic makeup. (*See* Statement of Basis, pp. 65-66.) The Air District continues to believe that there will not be any significant adverse impacts on any community regardless of demographic makeup.

Comment XV.2. – Mitigation Measures and the Local Community:

The Air District received comments questioning whether mitigation measures associated with the project will directly benefit communities located near the project site.

Response: This comment fails to identify a specific PSD requirement or any way where the Air District's permitting analysis or proposed permit conditions failed to satisfy such a requirement. The Air District therefore does not find anything in this comment that questions or objects to the issuance of the PSD permit or the terms of the permit, and thus does not provide any comment that the Air District needs to consider or respond to in its formal PSD response to comments. Nevertheless, the Air District provides the following response to inform the public to the greatest extent possible regarding this project. The Air District notes that all of the mitigation measures that will be provided regarding this project will benefit nearby communities.[371] Some of the mitigation measures address regional concerns that address the entire Bay Area, and in that respect they benefit neighboring communities as part of the Bay Area airshed as a whole. Other such measures will have a direct benefit to areas near the proposed facility in particular, for

[371] By "mitigation measures", the Air District interprets this comment to refer broadly to all aspects of the project that will reduce or offset potential environmental impacts from the project, including elements such as BACT control technology to reduce emissions, emissions offsets and other measures provided under state law to obtain emissions reductions from existing sources to counterbalance new emissions from this project, and measures required under CEQA to mitigate significant adverse environmental impacts to the greatest extent feasible. These "mitigation measures" go beyond what is required in the PSD analysis, and to the extent that the comments are aimed at non-PSD requirements – such as CEQA mitigation measures – the District notes that they are not relevant to the PSD permit analysis. The Air District nevertheless addresses all environmental mitigation measures to provide as much public information as possible.

example through measures to limit emissions of fine particulate matter that may impact areas around the facility. Other mitigation measures benefit natural resources enjoyed by everyone throughout the Bay Area and beyond, such as water quality in the San Francisco Bay and recreation areas in the vicinity of the facility and in the East Bay hills.

Comment XV.3. – Use of Health Risk Analysis to Evaluate Potential Impacts to Local Residents:

The Air District received comments claiming that District cannot use the same Health Risk Assessment methodology it uses for other projects to assess potential impacts to Environmental Justice communities. These comments claimed that minority populations have specific attributes that make them susceptible to air pollution impacts in unique ways. They claimed that the area around the proposed project location has a disproportionate number of people with diseases such as asthma, chronic lung disease, congestive heart failure and other chronic conditions, as well as higher overall mortality rates. Some comments claimed that students who attend an educational institution a mile to the west of the facility location, some of whom are non-white and some of whom may lack medical insurance coverage, are particularly sensitive to external environmental degradation. Other comments claimed that a 1998 EPA guidance document regarding environmental justice issues in PSD Permitting requires the Air District to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

Response: The Air District's Health Risk Assessment methodology is designed to take sensitive populations, such as those who may be particularly sensitive to air pollution concerns, into account.[372] This is an important consideration for all communities, as every community has some members who may have heightened sensitivity to potential airborne health hazards to some extent. The Air District supports its Health Risk Assessment methodology as an appropriate way to characterize the potential health risks associated with the proposed Russell City Energy Center with respect to communities that have members with heightened environmental sensitivities. The Air District has reviewed relevant EPA guidance on this issue and has not found any indication that such a Health Risk Assessment methodology cannot be used in evaluating Environmental Justice considerations.

Comment XV.4. – Cumulative/Synergistic Impacts Analysis:

The Air District also received comments asserting that the District should also have examined the "synergistic effects" of existing pollution sources in the area. These comments asserted that the District should analyze the cumulative impacts of the emissions from the Russell City project in conjunction with existing sources in the area.

Response: The Air District's Health Risk Assessment methodology addressed cumulative risk concerns by ensuring that new sources such as this one will not make add more than a *de minimis* contribution to any cumulative risk. For the reasons explained above in response to Comment XIV.3. (regarding the District's Health Risk Assessment methodology), the District's methodology does not evaluate each specific background source for every new project where the

[372] OEHHA's methodology for deriving health effects values (CPFs and RELs) are protective of public health and account for potential exposure to sensitive populations.

project's risk will be less than the *de minimis* level. For these reasons, the Air District does not currently conduct an evaluation of a project's addition to cumulative health risk in its Health Risk Assessment process. But the District certainly does share the commenters' concerns about air pollution sources in locations with existing elevated background level of toxic air contaminants. The Air District is implementing several initiatives to address these concerns. The Air District's Community Air Risk Evaluation ("CARE") program, for example, is designed to implement mitigation measures – such as grants, guidelines, or regulations – to achieve cleaner air for the public and the environment, with specific focus on heavily-impacted communities. Similarly, the Air District is in the process of adopting "Thresholds of Significance" under the California Environmental Quality Act that will add a heightened level of environmental review and mitigation for new projects located in areas with significant existing sources of toxic risk. These policies, along with the Air District's requirement that no new source of toxic air contaminants may contribute more than a *de minimis* additional amount of toxic risk, will help to address the problems associated with air toxics in impacted communities.

Comment XV.5. – Environmental Justice Outreach:

The Air District received comments asserting that the District should have conducted a broader public outreach regarding environmental justice concerns.

Response: The Air District believes that it has conducted a very robust level of public outreach regarding all aspects of this project, including environmental justice issues. The Air District widely publicized its proposal to issue the Federal PSD permit in the community, and held two public hearings at Hayward City Hall to allow residents to express their views on the proposal. Notably, the Air District went well beyond what is required by the Federal PSD regulations in providing notice to Spanish-speaking populations and in providing a translation service at the public hearing to ensure the broadest possible opportunity for public participation. This level of outreach more than satisfies the requirements for PSD permitting and for consideration of environmental justice issues.

XVI. THE FEDERAL PSD PERMIT EVALUATION AND ISSUANCE PROCESS

Comment XVI.1. – Compliance With PSD Delegation Agreement:
The Air District received comments claiming that EPA has determined that the Air District is not implementing the terms of the Delegation Agreement for issuance of Federal PSD Permits entered into between the Air District and EPA Region IX. Some of the comments alluded to the PSD permitting irregularities in the permitting history for a different PSD facility, the Gateway Generating Station. These comments suggested that the Air District should relinquish the delegation of PSD permitting authority back to EPA Region 9.

Response: The Air District disagrees with the assertion that it is not appropriately implementing the terms of the Delegation Agreement. To the contrary, the Air District is following the letter and spirit of the Delegation Agreement, as well as the requirements of 40 C.F.R. section 52.21 as required by the Delegation Agreement. The Air District further disagrees that it should not be taking the lead in processing PSD permits in the Bay Area under the Delegation Agreement.

Historically, the Air District interpreted the provision in the Delegation Agreement stating that permits issued in accordance with the provisions of District Regulation 2, Rule 2, are deemed to meet the Federal PSD permit requirements to mean that if the Air District followed its procedures for issuing District Authorities to Construct under Regulation 2, Rule 2, that it would satisfy the requirements of 40 C.F.R. section 52.21 as well. When the Federal PSD Permit for this facility was appealed, however, it became clear that this was not a legally tenable position and that the District would have to comply with all of the specific requirements of Section 52.21 and related authorities. The Air District has therefore corrected the defects in its PSD permitting procedures and is now following all applicable requirements to the letter, as required by the Delegation Agreement.

With respect to the Gateway Generating Station, after receiving the remand in this case the Air District examined the permitting record of other PSD facilities and discovered the irregularities in the permitting record for that facility. The Air District brought these irregularities to the attention of EPA Region 9 when they came to light, as the District is required to do under the Delegation Agreement, and EPA Region 9 determined that the facility had been built without a valid Federal PSD Permit. EPA Region 9 is currently engaged in an enforcement action regarding these claims. The Air District disagrees that anything in the history of the Gateway facility suggests that it is not properly implementing the Delegation Agreement. To the contrary, the experience with Gateway shows that the Air District has been following the requirements of the Delegation Agreement, initially under the interpretation that EPA was instructing the District to follow District Regulation 2, Rule 2 in issuing PSD permits, and more recently under the interpretation that it must follow the specific requirements of 40 C.F.R. section 52.21.

The Air District therefore disagrees with these comments that it is not properly implementing the Delegation Agreement. Furthermore, the Air District disagrees that there is any reason to give back the delegation of authority to EPA Region 9, either because of the EAB remand or for any other reason. Notably, the EAB's remand ordered the District to re-issue the Draft PSD Permit under delegated authority from EPA after remedying the defects identified in the Remand Order, and therefore implicitly affirmed the validity of the Delegation Agreement notwithstanding the defects the EAB identified and which have now been corrected.[373]

Comment XVI.2. – Compliance with EAB Remand Order:

The Air District received comments questioning whether this Federal PSD Permit application is being processed consistent with the EAB's Remand Order.

Response: In posing this question, the comments did not claim that the District is failing to process this permit application consistently with the Remand Order, and did not suggest that the District should be doing anything differently in order to comply with the requirements of the Remand Order. The question therefore does not contain a substantive comment for the District to respond to. Nevertheless, to the extent that this question was meant to imply that the District is not complying with the Remand Order, the District has reviewed its procedures generally to ensure that they are following the requirements of the Remand Order, and has concluded that the re-noticing and issuance of the Federal PSD Permit is fully consistent with the Remand Order.

Comment XVI.3. – Compliance with NSR Workshop Manual:

The Air District received comments noting that the District relied on EPA's 1990 NSR Workshop Manual as guidance for conducting its top-down BACT analyses. These comments questioned if the permit would differ if the District had applied what the comments referred to as present standards, which may have been intended to imply that the 1990 guidance document is somehow out of date.

Response: The Environmental Appeals Board has repeatedly affirmed the importance of the NSR Workshop Manual as valuable guidance for conducting a Federal PSD Permit analysis, including recently in *In re: Christian County Generation, LLC*, PSD Appeal No. 07-01 (EAB Jan. 28, 2008). The comments did not cite any area in which the Air District has relied on something in the NSR Workshop Manual that is out of date or has been superseded, and the Air District is not aware of any. The Air District therefore disagrees with this comment to the extent it was intended to imply that the Air District impermissibly relied on the NSR Workshop Manual.

Comment XVI.4. – Time Period for Processing Permit Application:

The Air District received comments claiming that the permit application for this facility was not processed in compliance with elements of 40 C.F.R. section 51.166, which requires (*inter alia*) that State Implementation Plans that incorporate PSD permitting programs include provisions requiring the state to make a final determination on PSD Permit applications within 1 year after receipt of a complete application. The comments implied that the Air District had not complied with applicable time limits for processing this permit application. The Air District also received some comments that cited various regulatory provisions establishing permitting timelines for power plant approvals (although these other comments did not expressly state that the Air District's actions were deficient in any way).[374]

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[373] *See* Remand Order at p. 42.

[374] These provisions included California Public Resources Code 25519(h), which provides that local agencies have 180 days to comment on an application for certification; District Regulation

Response: At the outset, the District notes that 40 C.F.R. section 51.166, the regulatory provision cited in these comments, sets forth requirements for state PSD programs to be approved by EPA into Clean Air Act State Implementation Plans. It does not apply to states issuing Federal PSD Programs on EPA's behalf under delegated federal authority. PSD permits issued under delegation of authority from EPA are subject to 40 C.F.R. section 52.21, not 40 C.F.R. section 51.166.

The District's NSR regulations governing District Authorities to Construct do incorporate by reference to the provisions of 40 C.F.R. section 51.166. But to the extent that this makes 40 C.F.R. section 51.166 applicable to the District's NSR permitting program, the District's program does fully comply with the requirements cited in the comments regarding making permit decisions within one year. (*See* District Regulation 2-2-407 & 2-3-405.)

Furthermore, to the extent that there was a one-year time clock for the Air District to make a final determination on the permit application here, the District did make a final determination here within one year after receipt of a complete application. The application was originally received by the District on November 28, 2006 (and was not accepted as complete until some time later),[375] and the Air District took final action to issue the Federal PSD permit on November 1, 2007. The Environmental Appeals Board subsequently remanded the permit to the Air District to reconsider its determination, which is why the permit is still before the Air District for decision, but that does not change the fact that the Air District did in fact take final action to issue the permit within one year after the application was submitted. And in the Remand Order the EAB instructed the Air District to undertake further proceedings to reconsider the determination it had made. The EAB did not instruct the Air District to reject the application because more than one year had past since the application was submitted.

Moreover, even if such a one-year requirement was applicable here and the Air District had failed to take action within a year, the remedy for any such delay would be to require the agency to make its determination as soon as possible. It would have no impact on the substance of the determination or on any conditions of the permit. For all of these reasons, the Air District finds

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2-3-403, which states that the District should make its Preliminary Determination of Compliance within 180 days after acceptance of a complete application; District Regulation 2-1-405 which states that the District should make its Final Determination of Compliance within 240 days after acceptance of a complete application; and CEC Regulation 1744.5, which also says that the District should make its Final Determination of Compliance within 240 days.

[375] A comment stated that the index of permitting documents that the District prepared for this project shows that Application 15487 for this facility was received in May of 2001. The Air District reviewed the index and did not find any reference to District Application 15487 having been received in May of 2001. The commenter may be confusing this application with an earlier application to the CEC for the original project, which is dated on the index May 2001, but that was not the District application for the current project. To the extent that the District made any indication that the application for the Federal PSD Permit the District is now issuing was submitted in 2001, that indication is in error.

nothing in this comment that has any impact on the proposed Federal PSD permit or the conditions therein.

Comment XVI.5. – Discretion to Deny Permit For Project That Satisfies All Requirements For PSD Permitting:

The Air District also received comments suggesting that the District has the discretion to deny the permit even if it complies with all applicable statutory requirements, quoting the language from the *American Corn Growers* case stating that nothing in the Clean Air Act provides for issuance of a PSD permit as a matter of right.

Response: The Air District agrees with the comments that a facility is not entitled to a Federal PSD Permit as a matter of right. To the contrary, a facility must comply with strict requirements as set forth in 40 C.F.R. section 52.21 in order to be eligible for a Federal PSD Permit. The Air District disagrees that it can or should deny a Federal PSD Permit for a facility that does satisfy these requirements, however. The Federal PSD Program was set up to ensure a balance between protecting air quality in attainment areas and allowing economic activity consistent with air quality goals. Where a project satisfies all applicable requirements of the Federal PSD Program, it is eligible for a PSD Permit. Moreover, to the extent that the Air District has the discretion to deny a permit even where it satisfies all applicable Federal PSD Permit requirements, the Air District has concluded that it should issue a Federal PSD permit for this project. As detailed in the District's analyses, the facility satisfies all applicable legal requirements for a PSD permit; it will utilize current state-of-the-art electrical generating equipment and pollution control equipment; it will have the lowest emissions of any similar facility generating the same amount of electric power; and it has been determined by the CEC to be an appropriate facility for this location. Although the PSD permit review is independent of and not subordinate to the CEC's licensing decision under California law, the Air District is mindful of the California legislature's intention that the CEC should be the primary decision-making body with respect to new thermal power plant siting decisions in California. The Air District would therefore be hesitant to second-guess the CEC's licensing decisions in the context of a Federal PSD permitting review where the proposed project satisfies all applicable PSD requirements, even if it had the discretion to do so. For all of these reasons, the Air District disagrees that it can deny a Federal PSD permit for a project that satisfies all applicable PSD requirements, and in any event would not find it appropriate to do so here even if it had the discretion to do so.

Comment XVI.6. – Non-Attainment NSR Permitting For Projects Impacting Adjacent Non-Attainment Areas:

The Air District received comments noting the difference between the PSD permitting requirements applicable in attainment areas and the Non-Attainment NSR permitting requirements applicable in non-attainment areas, and stated that the District needs to conduct a Non-Attainment NSR analysis for the proposed facility. The commenters implied that the Non-Attainment NSR analysis needs to be conducted for $PM_{2.5}$ and for ozone.

Response: The Air District has undertaken a Non-Attainment NSR permitting analysis for this facility under its District NSR regulations, District Regulation 2, Rule 2 (as incorporated for power plants by Regulation 2, Rule 3). This analysis, which was incorporated into the CEC's overall environmental review for the project, resulted in the District's Authority to Construct (which implemented the CEC's Air Quality conditions of certification). That Non-Attainment NSR permit was appealed and upheld. The Air District therefore disagrees that it needs to conduct further Non-Attainment NSR analysis for this facility.

The Air District also notes that with respect to $PM_{2.5}$, under 40 C.F.R. Part 51, Appendix S, facilities are subject to permitting requirements only if they emit over 100 tons per year of $PM_{2.5}$. Since this facility will emit less than 100 tons per year of $PM_{2.5}$, it is not subject to Non-Attainment NSR requirements for that pollutant. The Air District explained this situation in the Additional Statement of Basis (*see* pp. 54-55), and the District finds nothing in these comments to suggest that the analysis is incorrect.

Comment XVI.7. – Integration of Non-Attainment NSR and PSD Permitting:

The Air District received comments requested clarification regarding whether the Non-Attainment NSR and PSD permitting for the Russell City facility was conducted in an integrated permit proceeding. Some comments also requested clarification on whether Non-Attainment NSR permitting for $PM_{2.5}$ would be conducted in an integrated proceeding if and when the Bay Area's non-attainment designation for $PM_{2.5}$ becomes effective and why it would make sense to do so.

Response: The Air District responds by clarifying that under its Delegation Agreement with EPA Region 9, it conducts Non-Attainment NSR permitting and PSD permitting in an integrated proceeding. This is how the permitting for this facility has been conducted. The District issued the Non-Attainment NSR permit (the District's Authority to Construct) and the PSD permit at the same time, on November 1, 2007. The District Authority to Construct was appealed and upheld, and so that permit has become final. The PSD permit was appealed and remanded, and so the Air District is conducting further proceedings for that permit in response to the EAB's order. With respect to Non-Attainment NSR permitting for $PM_{2.5}$, the Air District has consulted with EPA Region 9 as to how that permitting will be conducted, and EPA Region 9 has authorized the District to conducting permitting for those requirements in the same integrated proceeding. It makes sense to do so because it is simpler for all concerned, including the agencies, project applicants, and members of the public, for a single agency to address as many permitting requirements as possible that may apply to a facility in one integrated permit proceeding. Nothing in these comments suggested that there was anything defective in how the Air District has undertaken the integrated permitting process here, and so the District finds nothing in the comments to provide cause to change any permit conditions or decline to issue the permit.

Comment XVI.8. – History of Permitting Process:

The Air District received comments claiming that some of the analysis underlying the District's proposal to issue a PSD permit for this facility, including CEC analysis regarding what kind of generating capacity is needed in California, is "stale" and "scattered over the last decade".

Response: The Air District disagrees that its analysis supporting the Federal PSD Permit for this facility is not current. All of the provisions of the permit are supported by a current up-to-date analysis as set forth in the Statement of Basis and Additional Statement of Basis documents, these Responses to Comments, and in the other documentation the Air District has relied on for this permit. In any areas where this analysis has relied on work performed earlier on in the permitting process, the Air District has reviewed it to ensure that it is still current, and has updated it in any areas where it was not current. The comments the Air District received on this issue did not point to any specific areas where the District's analysis was out of date, and the Air District is not aware of any. The Air District therefore disagrees with these comments and finds nothing in them to provide cause to change any permit conditions or decline to issue the permit.

XVII. FEDERAL PSD PERMIT NOTICE & COMMENT REQUIREMENTS

The Air District received a number of comments addressing the procedural requirements for processing Federal PSD Permit applications, including public notification, publication of the District's rationale for the proposed permit conditions, and an opportunity for public comment on the proposed permit. The Air District responds to these comments in this section.

A. Public Notice of District Actions

Comment XVII.A.1. – Public/Agency Notification of PSD Review Process:

The Air District received comments asking whether the District provided notice of the proposed Federal PSD Permit to a number of governmental entities, as well as other organizations, stakeholders and members of the public. These comments made specific reference to entities and individuals to whom notice is required under the applicable Federal PSD notice requirements and the Air District's Delegation Agreement with EPA Region IX.

Response: The Air District provided notice to all individuals, governmental bodies, and others who are entitled to it as required by the applicable PSD notice regulations and the Delegation Agreement. Copies of all of the public notice documents for this permitting action, including mailing lists, proofs of newspaper publication, *etc.*, are included in the record documents the Air District is making available in this matter. The Air District notes that the significant public interest expressed in this project highlights the fact that the District's public notice and outreach efforts were very broad and robust.

B. Information Provided to the Public/Explanation of Basis for Proposed Permit

Comment XVII.B.1. – Statement That A PSD Permit Was Issued In 2002:

The Air District received comments during the first public comment period stating that the Air District had incorrectly stated that a Federal PSD Permit had been issued for this project in 2002 along with the state-law permitting documents. These comments stated that there was no Federal PSD permit issued at that time, and that as a result the Air District could not treat the current permitting action as an amendment to an existing permit. The Air District corrected the record on this point when it issued the Additional Statement of Basis in August of 2008, and clarified that it was issuing a new Federal PSD Permit, not an amendment to a previously-issued permit. The Air District further explained that its original permit analysis, as well as all of its subsequent additional analyses, was based on a review of the project as a new project and not as an amendment, and that the project as a whole complies with all Federal PSD requirements for a new project. (*See generally* Additional Statement of Basis at pp. 5-6.) Subsequent to publishing this further discussion of the issue, the Air District received further comments during the second public comment period. The further comments acknowledged that the Air District had corrected the record in this regard, but objected that the Air District had not adequately explained this detail in the August 2009 public notice and related documents. These comments also stated that a project Fact Sheet that the Air District prepared (in addition to the formal public notice and Additional Statement of Basis) included conflicting information on this issue, explaining that the

District was not proposing to issue the permit as an amendment but also referencing the older incorrect information about the amendment. These comments suggested that the proposed permit should be re-noticed for further public comment to provide further information and explanation regarding this situation.

Response: The Air District disagrees that it has not fully explained for public review that this is a new permit and not an amendment to an existing permit, and further disagrees that it did not adequately inform the public of this situation. The Air District clearly explained the situation in the Additional Statement of Basis, and corrected the earlier misstatements regarding whether a PSD permit had been issued initially. Any interested member of the public who has been following this permitting proceeding would have been aware of these facts from reviewing the Additional Statement of Basis. The fact that the public was not misled by this situation is further underscored by the fact that members of the public have not felt constrained to comment only on a subset of issues that they may have believed were involved in an "amendment" to an earlier permit. To the contrary, a review of the comments the Air District has received on a wide variety of issues involving this project, including in many areas where the analysis and issues have not changed since the project was initially proposed. Indeed, this situation is not surprising given that the Air District conducted a full review of all aspects of the project, including elements that are not changing, even in the initial Statement of Basis that was put forward as involving an amendment to an existing permit. This breadth of comment that the Air District received controverts the assertion made in these comments that the public was misled in any substantive way by the Air District's treatment this issue.

Some of the comments appear to criticize the Air District's August 2009 public notice for not having explicitly called out this issue in the text of the notice, and for instead referring interested members of the public to the Additional Statement of Basis. The Air District disagrees that it misled or misinformed the public in this regard. Correcting such a misstatement in an additional statement of basis document is not something that needs to be specifically identified in the public notice on the document under the Federal PSD notice requirements where it is made clear in the statement of basis document. (*See* 40 C.F.R. § 124.10(d).) Moreover, the public notice clearly referenced the Additional Statement of Basis for more information, and that document provided the full explanation of the amendment/new permit issue. Interested members of the public therefore had full notice of the Air District's further explanation, and any interested members of the public who followed up by reviewing the Additional Statement of Basis would have seen the Air District's full explanation.

For all of these reasons, the Air District disagrees with these comments stating that it should provide further public notice regarding the fact that this is a new permit, not an amendment to an existing permit.

<u>Comment XVII.B.2. – Identification of Project Location:</u>

The Air District received comments questioning how the project location was identified in the permitting documents. The comments questioned whether the site should have been identified by its geographic location in relation to nearby landmarks (*i.e.*, its proximity to certain geographical features such as the San Francisco Bay, *etc*.) instead of by street address and nearest road intersection. The comments also questioned whether the Air District had adequately described how far the current project location is from the original project location and the reasons why it was relocated. Some comments suggested that the project location was not adequately identified in the public documents supporting the permit, and that the areas surrounding the project location were not adequately identified sufficient to inform the public of where the project would be located and what the surrounding area is like. Some comments also stated that the Air District did not properly advise USFWS and other public agencies of the actual site, and stated that the Air District misled these agencies by describing the location as industrial without referencing its proximity to the Hayward shoreline.

Response: The public notices that the Air District issued cited the specific project location giving the street address and nearest cross-streets, which afforded members of the public full notice of exactly where this project will be located.[376] Identifying the specific location in this respect gave members of the public full information sufficient to locate the project site in relation to any other geographic features that may have been of interest to them. Indeed, with the specific project location, members of the public were able to visit the project location and see for themselves exactly where it will be located and what the surrounding areas are like. This information gave the public full notice of the project's location as well as surrounding areas, including features such as the industrial nature of the area and its proximity to the Hayward shoreline.[377] And the Air District received a large volume of comment regarding the project's location and setting from members of the public who were fully able to understand and identify where it would be located, where it would be in relation to nearby areas of concern, and what the surrounding setting is like. These comments, which are based on a clear understanding of where the project will be located, belie the comments suggesting that the public was not adequately informed of the project location.

<u>Comment XVII.B.3. – Information Regarding Procedural Posture of Permitting Action:</u>

The Air District received comments questioning whether additional information regarding the procedural posture of this permitting action, including the prior procedural history and avenues

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[376] Some comments also criticized a revised public notice the Air District issued to correct the facility mailing address that had been incorrectly listed in an earlier notice. These comments stated that although the Air District corrected the facility address, it did not explain exactly which of the various addresses contained in the notice (*e.g.*, the company headquarters, the address for submission of public comment to the Air District) had been corrected. The Air District disagrees that this corrected public notice was insufficient or unreasonably confusing in this regard. If any member of the public who received the second notice was confused about which address had been corrected from the initial notice, that person could easily have compared both notices to see what had changed.

[377] The District also received several comments regarding the use of the "Russell City" name for the facility. Some commenters objected to the use of this name because the city in which the facility is officially located is the City of Hayward, CA. Other comments praised the use of the "Russell City" name in recognition of the unincorporated community that historically existed in the area that was known by that name. The facility's name is not relevant to any PSD permitting issues, and the Air District disagrees that there is any way that any members of the public could be misled by the use of this name given all of the information the Air District provided regarding the location of the facility.

for potential further appeals, should have been more explicitly described in the permitting documents. The comments questioned whether the Statement of Basis should have described other avenues for appealing permits for this facility, besides appeal of the CEC license to the California Supreme Court, appeal of the District Authority to Construct through the state appeals system, and appeal of the federal PSD Permit through the Federal appeals system. The comments questioned whether the Statement of Basis should have noted that Alameda County was one of the parties that appealed CEC denial to Supreme Court; and that the Supreme Court dismissal was "without review". The comments similarly questioned whether additional details regarding the EAB remand should have been provided.

Response: The Air District notes that these comments merely asked questions about what information the Air District should have provided in its permitting documents, and did not identify any area where the Air District did not provide sufficient information or identify any additional information the Air District should have provided. These questions therefore do not contain any substantive comment that the Air District is required to respond to. To the extent that the questions can be construed as comments suggesting that the Air District in fact was deficient in the information it provided regarding appeals procedures, the Air District disagrees that it was required to provide any further information under the applicable Federal PSD requirements. The Federal PSD requirements in 40 C.F.R. section 52.21 and 40 C.F.R. Part 124 do not require that the Air District specify the appeals procedures for any permits or approvals at the draft permit stage. (*See* 40 C.F.R. §§ 124.7-124.10.) The Air District provided the information in its Statement of Basis and related documents over and above the minimum required by the Federal PSD requirements in an attempt to inform the public as much as reasonably possible regarding how the overlapping state and federal licensing/permitting process works for power plants in California. The Air District considers the information it provided – specifying how the CEC license, the Federal PSD permit, and the District Authority to Construct, respectively, are issued and how the can be appealed – to have done a very good job in achieving this goal, and disagrees that there was any more information that it should reasonably have provided (let alone was *required* to have provided under the Federal PSD permitting requirements). The comments on this issue do not identify (expressly or even impliedly) any reason where the permitting process for this PSD permit was defective.

Comment XVII.B.4. – Information Regarding Project Ownership:

The Air District received comments asking whether the public notice issued for the proposed permitting action should have included more information on the ownership of the project applicant, Russell City Energy Company LLC.[378] The comments noted that the project owner, Russell City Energy Company LLC, is an affiliate of Calpine Corporation. The comments asked about the details of these companies' affiliation, and asked whether General Electric (GE) has any affiliation with Russell City Energy Company LLC and whether GE has an ownership interest in the project. These comments suggested that these corporate relationships need to be explained in the permitting documents and in the public notice of the District's proposed permitting action under the requirements of 40 C.F.R. Part 124.

[378] The Air District also received questioning whether the project owner's address was correctly listed. The Air District is not aware of any inaccuracy in the project owner's address, and the comments have not identified any.

Response: Under 40 C.F.R. Part 124, the public notice is required only to identify the project owner, which is the Russell City Energy Company, LLC. The public notice is not required to identify other persons or entities that may have an ownership interest in the company that owns the project. The Air District went over and above what is required by Part 124 in identifying the owner's affiliation with Calpine Corporation, which is a corporate parent company that is more widely identifiable than the entity that actually owns the project. This was information that the Air District thought might be of interest to members of the public, even though it was not required by Part 124. The Air District does not believe that further information about the corporate ownership of Russell City Energy Company, LLC would have been of great public interest, or that it should have reasonably been included in the description of the project owner. The Air District does not find any information in these comments to suggest that this conclusion was unreasonable or unwarranted. Certainly, there is nothing in these comments to suggest that the public notice was deficient in any way, as information on parent companies and corporate affiliations is not required under Part 124.

Moreover, these comments do not suggest that there are any facts regarding project ownership that would bear on any of the issues involved in the PSD permitting process or suggest that any permit conditions should be changed. Thus, to the extent that these comments state that additional information should have been explained in the permitting documents, they do not explain how that information would have affected the outcome of the process or resulted in a different determination on the permit or in different permit conditions.

For all of these reasons, the Air District finds nothing in these comments to suggest that its permitting process and ultimate permit decision have been flawed or need to be revisited in any way.

Comment XVII.B.5. – Additional Detailed Information Not Required For PSD Permit Analysis:

The Air District received comments questioning whether its public notices and Statement of Basis documents should have included additional detailed information regarding the project and its emissions.

Response: The Air District disagrees that the level of detail it provided in its public notices and in its Statement of Basis documentation was insufficient to provide the public with adequate notice of this project and information on which to review the Air District's permitting decision. The Air District has provided a large amount of information to the public in order that interested parties can understand what this facility will involve and can review the Air District's permitting analyses with respect to the facility and the applicable Federal PSD requirements. The Air District is not aware of any information relevant to any part of the Federal PSD Permit process that the Air District has not made publicly available, and the comments have not identified any. The comments have pointed to some information that is not relevant to the permitting analysis and suggested that it needed to be made available and/or included in the public notices for this facility, but the Air District disagrees that such information must be identified or made available if it is not part of the Federal PSD analysis.

Comment XVII.B.6. – General Criticisms of the Statement of Basis:

The Air District also received comments generally criticizing the Statement of Basis. These criticisms include claims that the Statement of Basis was poorly organized, that units of measure and their abbreviations are not defined, that numbers in different tables appear to contradict each other, that tables do not include notes with the information necessary to explain them, *etc*.

Response: The Air District strives to make its public documents as clear and understandable as possible, and will consider these suggestions on how to improve the various reports and analyses it publishes for public review. The Air District disagrees, however, that overall the documents it has published with respect to this permitting action have been insufficient to adequately inform the public of the principal facts and significant factual, legal, methodological and policy questions considered in reviewing this permit. Despite the criticisms voiced in these comments, the Statement of Basis and related documents clearly described the type of activity that will be involved with this project, the type and quantity of emissions that will be involved, the potential for consumption of PSD increments, the basis and derivations of the applicable permit conditions and the reasons for them, and information on how to participate in the proceeding and how to get more information. These comments have not identified any specific area where the Air District's documentation was not sufficiently clear and understandable under the circumstances, and have not identified any particular issue in which the Air District's analysis was not sufficiently explained in order to allow for informed public review. Moreover, the comments have not identified any permit conditions they claim are inappropriate, or not adequately substantiated by sufficient explanation or analysis. For all of these reasons, the Air District does not find any reason in these comments not to issue the Federal PSD permit.

Comment XVII.B.7. – Responses To Questions Submitted by Commenters:

The Air District received comments stating that the District should provide answers to certain questions the commenters submitted during the initial public comment period, and should keep the public comment period open until the Air District has done so and until the commenters have had a chance to review such responses.

Response: The Air District has gone to great lengths to provide the public with relevant information regarding the Russell City project and the District's permitting analysis for it. The Air District has provided all of the information necessary for the public to understand the District's analysis and its basis for issuing the permit. The Air District disagrees that there is further information that it needs to provide at this stage before making a final permit determination. To the extent that the commenters' questions can be construed as containing comments on the District's analysis and the draft permit, the Air District is responding to them in this Responses to Comments document.

C. Opportunities For Public Comment

Comment XVII.C.1. – Opportunities to Submit Comments:

The Air District received comments questioning whether it complied with several regulations dealing with public comment opportunities, including 40 C.F.R. § 51.166(q) (public participation for SIP-Approved PSD programs); 40 C.F.R. § 124.13 (longer comment period to the extent shown to be necessary); 40 C.F.R. § 124.8 (Fact Sheet); and 40 C.F.R. § 124.6 (Draft Permits).

Response: The Air District has complied with all applicable requirements for providing public comment opportunities for this PSD permit. The public comment requirements are set forth in 40 C.F.R. Section 52.21 and the relevant provisions of 40 C.F.R. Part 124, and the Air District has not only fully satisfied all applicable requirements, it has even gone well beyond the minimum required in many areas. In particular, the Air District provided two public comment periods, each well over the minimum 30 days required by the regulations. The comments have not identified any reason why the time periods provided for public comment were insufficient, or why there may be a need for additional time for public comment pursuant to 40 C.F.R. section 124.13. Moreover, the Air District provided what the regulations call "Fact Sheets" under 40 C.F.R. section 124.8 (what the Air District called the "Statement of Basis" and "Additional Statement of Basis"), which set forth the degree of PSD increment consumption expected, which is less than significant here for the PSD pollutants for which increments have been established; a detailed summary of the basis for the draft permit conditions, with appropriate references to governing authority and to documentation in the Air District's permitting file;[379] a description of how the Air District will make its final decision on the draft permit describing the comment process and the public hearing that was being held; and the name and phone number of a contact person for more information. Furthermore, the Air District circulated for public review its Draft Permit setting forth all of the proposed permit conditions as required by 40 C.F.R. section 124.6 (both as initially proposed in December of 2008 and as revised in the August, 2009, proposal). In this way, the Air District fully complied with all of the requirements for providing the public opportunities for comment on the draft permit.[380] The Air District also notes that the large volume of public comment received is a testimony to the robust comment opportunity that was provided. The Air District notes that these comments simply questioned how the Air District complied with these requirements and did not point to any area where they claimed the Air District's efforts were deficient. But to the extent that the comments

[379] Note that in this manner the Air District essentially provided a formal public administrative record for the Statement of Basis, even though this is required only where EPA is the issuing agency (*see* 40 C.F.R. § 124.9). The District believes in providing public access to a written record as a matter of governmental transparency and good administrative practice, even though it is not required by law for Federal PSD Permits. Moreover, to the extent that the administrative record requirement is found to be legally applicable to permits issued by state agencies, the Air District believes that the record it made available for public review would satisfy the requirement.

[380] The comments cited some authorities that are not applicable to this project. For example, 40 C.F.R. Section 51.166 applies to State PSD programs seeking approval by EPA in a State Implementation Plan. It provides requirements for states in writing their plans, and does not establish requirements for individual permitting actions. For Delegated Federal permitting actions such as this one, the requirements for the individual permitting action are set forth in 40 C.F.R. Section 52.21 and 40 C.F.R. Part 124, not in 40 C.F.R. Section 51.166. In other areas, specific subsections of requirements in 40 C.F.R. Part 124 are not applicable by their terms, such as the requirement to specify any variances under Section 124.63 in a draft NPDES permit, which is inapplicable because this is not an NPDES permit there are no such variances here in any event.

were intended to suggest that the Air District's efforts were deficient in some way, the Air District disagrees for the reasons explained above.

<u>Comment XVII.C.2. – Openness to Considering Public Comments:</u>

The Air District received comments suggesting that it is not in fact open to considering comments from the public regarding the proposed permit, and is using the public comment process simply to create a record for foregone conclusions about whether and how this facility should be permitted. These comments claimed that the Air District had already decided on its final determination regarding this permit before taking public comment. They claimed that the Air District has been hostile to public comment and has attempted to prevent public input.

Response: The District strongly disagrees with these comments. The Air District went well beyond the minimum legal requirements in providing public outreach and in encouraging public interest in this permitting action. The Air District very much appreciates the insightful comments it received from the public, and in fact has incorporated a number of comments to improve the permit. For example, based on public comments (among other information), the Air District has revised the Carbon Monoxide BACT limit downwards from 4.0 ppm to 2.0 ppm. Similarly, the Air District revised the voluntary Greenhouse Gas BACT analysis that the applicant requested to result in a lower BACT emissions level as well as an annual compliance test requirement to ensure that efficiency does not unduly degrade over time. The Air District also reviewed its startup BACT analysis based in part on public comments and is finalizing the permit with more stringent startup limits as a result. These actions speak for themselves, and show that the Air District had not made up its mind regarding the final permit and in fact changed its mind based in part on comments received from the public. These actions highlight the fact that Air District does greatly value public input on its permitting actions, and has acted on the public's input in this case to strengthen the final permit.

<u>Comment XVII.C.3. – Other Communications Received Outside of the Formal Notice-and-Comment Process:</u>

The Air District also received comments asking whether other submissions from the public, such as comments received during comment periods for earlier permitting determinations, comments submitted during comment periods for other facilities, and documents filed in permit appeal proceedings, have been considered in these Responses to Comments.

Response: The Air District is legally obligated to consider and respond only to comments submitted during the comment periods on the current permitting action, which includes the two comment periods it provided on its draft Federal PSD Permit. The Air District has reviewed and considered all such comments, as provided in this Response to Comments document. As a matter of practice, however, the Air District reviews all other relevant information it may receive or may have received in the past regarding the permit under review, even if that information may not have been made as a formal comment during the comment period that the District is required to consider and respond to. In this way, the Air District can ensure that it incorporates the best information into its permitting analyses even if that information did not come to light in a formal comment. The Air District has done so here, and has considered additional information received outside of the two formal comment periods provided for the current permitting action. Any such submissions from the public are not formal public comments in this proceeding that need to be responded to on the record, however, and so the Air District has not formally identified any such additional information received and provided a formal written response (although where certain information has touched on relevant issues, these Responses may cover those communications as well).

Comment XVII.C.4. – Recirculation For Further Public Comment:

The Air District received some comments suggesting that the District should re-circulate revised PSD permitting analyses for additional public review and comment.

Response: The Air District agreed that the revisions it made to the proposed permit after the first round of public comments would benefit from further public review and comment. The Air District also conducted additional evaluation and analysis, including the PM2.5 source impact analysis and revisions to other analyses, and agreed that it would be beneficial for the public to review and comment on them. The Air District therefore published its Additional Statement of Basis and revised draft permit and held a second public comment period, including a second public hearing. After two rounds of public comment, the Air District does not believe that a further public comment period is necessary. The Air District is making only minor changes in the final permit as compared to the most recent draft it published and took comment on, and these minor changes do not change the substance of the permit conditions in any material way. The public has had full notice of the Air District's proposal to issue this Federal PSD permit and full opportunity to comment on the permit, the conditions it includes, and the analyses on which it was based.

Comment XVII.C.5. – Multi-Jurisdictional Permitting Process:

The Air District received comments that recited the history of the permitting process involving the CEC and the Air District and the various state-law and federal permits involved, and stated that the process has been "bifurcated" and difficult to follow by members of the public. These comments implied that this permitting history impeded informed public participation and is incompatible with the requirements for PSD permitting.

Response: The Air District disagrees that the fact that the permitting history for this facility has been bifurcated and involves overlapping state and federal permitting requirements impedes informed public participation or is incompatible with applicable Federal PSD permitting requirements. The permitting process for a facility such as a new power plant may be relatively complicated, but that does not mean that members of the public cannot understand it. Indeed, the detailed comments the Air District received from many members of the public – both from trained environmental professionals and from laypeople with no formal environmental or regulatory training – shows that the public can follow and participate in the permitting process before the various agencies that are involved in the permitting of new power plants. Moreover, these comments have not identified any area where the Federal PSD requirements are inconsistent with a permitting process such as the process that the Russell City Energy Center has gone through, and the Air District is not aware of any. To the contrary, the Environmental Appeals Board has explicitly reviewed the overlapping permitting process applicable to power plants in California in several cases, and has not found anything inconsistent. For all of these reasons, the Air District disagrees with these comments. The Air District finds no reason why the public cannot adequately participate in the power plant permitting process as it is set up in

California, nor any reason why the public could not participate fully here. The Air District finds nothing in these comments to suggest that it cannot issue the Federal PSD permit here or that any permit conditions are inappropriate or should be changed.

D. Public Availability Of Supporting Information

Comment XVII.D.1. – Public Availability of the Permitting Record:
The Air District received a number of conflicting comments regarding the documentation that it made available regarding its permitting analysis for the project. On the one hand, some commenters expressed appreciation that the District made its documentation available for the public to review and that District staff had provided them with information. One the other hand, some commenters claimed that the District had not made its supporting documentation sufficiently available for review.[381] Some commenters stated that the Air District should have developed a formal "docket" for its underlying documentation. Some commenters also stated that the documentation that the Air District made available for public review is voluminous, and that it was difficult for members of the public to review it because they either had to come to the District's headquarters in San Francisco to review it there in person, or pay for photocopying which would have been expensive. These comments stated that the District should provide electronic access to the documents and provide an additional 30-day comment period.

Response: The Air District agrees with the comments expressing praise for how it made its records available, and disagrees with the comments stating that the Air District's efforts were inadequate. The Air District notes that when it issued its initial Statement of Basis in December of 2008, it made all of the documentation supporting the analysis in the Statement of Basis available at that time, and a number of interested members of the public came to District headquarters to review it and to have copies made to take away. When the Air District issued its Additional Statement of Basis in August of 2009, it made further documentation available (along with what was initially made available) supporting the additional analysis in that document. At that time, the Air District also compiled an index of all of the documentation it was making available for public review, and published the index on its website. A number of interested members of the public came in to review this additional information as well.

These efforts to make the documentation supporting the Air District's permitting analyses available to the public more than satisfy the public participation requirements of the Federal PSD Regulations. For state agencies issuing PSD Permits pursuant to a Delegation Agreement, the applicable Federal PSD Regulations do not require the agency to make any documentation available, as the applicable requirements for making the permitting record available for public review and inspection apply only when EPA is the permitting authority. (*See* 40 C.F.R. §§ 124.9, 124.11, 124.10(d)(1)(vi).) Nevertheless, despite the absence of a legal requirement, the Air District makes its permitting documents available for public review in order to encourage informed public participation, which is what it did here.

[381] Interestingly, the commenter who objected to the way the Air District made its documentation available for public review also incorporated by reference the comments praising the District for how it made its documentation available to the public.

The Air District also disagrees that it was required to maintain a formal "docket" for its permitting files and that it was required to make all such documentation available electronically on the internet. As noted above, there is no requirement to make the underlying documentation available at all for permits that are issued by State agencies and not EPA. But even if the requirements applicable for EPA-issued permits were applicable, there is nothing in the regulations that states that a formal "docket" must be maintained, or that they must be made available electronically. Moreover, the Air District did make its index of documents available electronically, which allowed members of the public to review what was available and to request copies of specific documents without having to visit District headquarters in person.

Comment XVII.D.2. – Air District Responses to Requests for Documents Under the California Public Records Act:

The Air District received comments claiming that the commenter had requested access to District records regarding the permitting of this facility under the California Public Records Act, but was denied. These comments suggested that the Air District had failed to adequately inform the public of the underlying basis for its proposed permit such that the public could understand and comment on the proposed permit.

Response: The Air District has responded to all California Public Records Act requests regarding public records for this facility. Moreover, in addition to and separate from responding to all Public Records Act requests, the Air District made all relevant documents regarding the permit available for public review. There is therefore nothing in these comments that suggests that the Air District failed to adequately inform the public of the underlying basis for the permit or that the public did not have adequate information on which to evaluate and comment on the proposed permit.

The relevant history of the public records act requests regarding this facility is as follows. Mr. Rob Simpson submitted a Public Records Act request on September 11, 2008, in which he requested all Air District documents regarding the facility "subsequent to EPA Remand," which the EAB issued on July 29, 2008. The Air District began working on responding to that request, and provided the documents from the permit engineer's working file – which were the most relevant and readily available documents – one week later, on September 18, 2008. To provide a complete response, the Air District then conducted a comprehensive records search of all records created since the EAB Remand Order on July 29, 2008, that could be located anywhere within the Air District's possession. This included searching paper records as well as electronic records such as email correspondence and other electronic files such as word processing documents and PDF documents stored on the Air District's central computer servers as well as on staff's individual computers. This search included paper and electronic files from the large number of Air District staff who have worked on or had contact with this project from multiple Air District divisions. Once all of the public records since the EAB Remand Order had been collected, they were reviewed by legal counsel to remove any documents not subject to public disclosure, such as privileged attorney-client communications. When all of these tasks were completed, the full set of responsive records – which constituted several boxloads of records – were made available for the requestor to review, on December 18, 2008. During this time period, the requestor also engaged in a large volume of email correspondence with various Air District staff, and in some of those emails suggested that he wanted to review additional documents beyond the documents "subsequent to EPA Remand" that he had originally requested. After some further communications to ascertain exactly what universe of records he was requesting, on January 15, 2009, the commenter clarified that he was requesting all documents anywhere within the Air District's possession related to the Russell City facility "from 2008 and this year [2009]". The Air District therefore began the process of compiling and reviewing all documents related to the facility back to January 1, 2008, as it had done with the requestor's first request of September 11, 2009. The Air District completed these tasks and made the requested documents available for the requestor's review on June 15, 2009. The Air District has therefore responded to all Public Records Requests regarding this facility.

Moreover, during this time period, the Air District made available for public review and inspection all of the relevant documentation on which its Proposed PSD Permit and Statement of Basis were based. These documents were made available for review at the Air District's headquarters at the start of the public comment period by any member of the public interested in the proposed permit, without the need for a special request under the California Public Records Act or otherwise. The location and availability of these documents was published in the Air District's public notice of the proposed permit and in the Statement of Basis. Several interested members of the public took advantage of the public availability of these documents and came in and reviewed them (or took copies to review elsewhere). Indeed, one commenter even praised the Air District for its efforts in making the documentation accessible to the public, which comments Mr. Simpson incorporated by reference. The Air District also made all of this documentation available during the second comment period, as well as additional documentation that it had used in the further analysis undertaken for the August 2009 Additional Statement of Basis.

Mr. Simpson, who submitted the Public Records Act Requests, therefore had full access to all of the *relevant* documentation during both comment periods,[382] even if the Air District had not fully responded by the close of the initial comment period to his very broad Public Records Act requests for *all* documents in any way related to the facility anywhere within the Air District's possession. The only documents that had not been made available at that point were documents that may have related to the facility in some way but not used or relied on in the District's permitting analysis. These could have included documents such as communications regarding tangential issues, housekeeping matters such as arranging meetings to discuss the project, and so forth. Mr. Simpson was entitled to review these documents under the California Public Records Act, and the Air District did ultimately make them available to him, but they were not documents on which the Air District's proposed permit and Statement of Basis were based and thus were not necessary for a full understanding of the Air District's proposed permitting decision. The Air District therefore disagrees that there was any reason to keep the first comment period open until it had fully responded to Mr. Simpson's requests. But in any event, the Air District provided a further public comment period, and by that time it had responded fully to all outstanding records requests. To the extent that there was any information in the additional documentation requested by Mr. Simpson in his Public Records Act requests, he had a chance to review that information

[382] Notably, during the first comment period the Air District repeatedly reminded Mr. Simpson of the documents it had made available for public review during the comment period and invited him to review them in order to understand the basis for the proposed permit.

and submit comments based on it during the second comment period. (The Air District explicitly stated in the Additional Statement of Basis that it was inviting any comments the public may have based on evidence or information that was not ascertainable during the initial comment period (*see* Additional Statement of Basis at p. 3).) The Air District therefore disagrees that it failed to adequately inform the public of the basis for its permitting decision with respect to the underlying documentation, as it made all of the supporting documentation available during both comment periods, and made the additional information Mr. Simpson requested available within a reasonable time period and during the whole of the second comment period. Mr. Simpson cannot claim that he (or any other member of the public) was not fully informed of the basis for the Air District's proposed permit.[383] The Air District also notes that Mr. Simpson did not register any further objection during the second comment period, did not request any further documents, and did not suggest that the Air District should have made additional documentation available during the second comment period.

Finally, with respect to whether the Air District failed to comply with any applicable legal requirements, the Air District has in fact gone well beyond the minimum legal requirements in making its permitting documentation available for public review. The Air District notes that the Federal PSD requirements require the permitting record documents to be made available only for EPA-issued permits, not for permits issued by state agencies such as the Air District, as discussed above. (*See* 40 C.F.R. §§ 124.9, 124.11, 124.10(d)(1)(vi).) But in any event, the Air District did make all of its relevant underlying documentation available for review by the public, including Mr. Simpson, during the two comment periods on the permit. The Air District did not provide the additional very broad set of documents Mr. Simpson requested in his Public Records Act requests before the close of the first comment period, but providing such a response was not required in order to fully understand the basis for the proposed permit, and was not required by the Federal PSD regulations. And ultimately, the Air District did in fact provide the requested records before the second comment period, so to the extent that it was legally required to provide a comment opportunity after responding to outstanding records requests, it did so here. For all of these reasons, the Air District disagrees that there was anything defective in its actions to inform the public about the basis for this permit, including making all supporting documentation publicly available.

E. Prior Permitting History

Comment XVII.E.1. – No PSD Permit Issued in 2002:

The Air District received comments noting that the District did not actually issue a PSD permit in 2002 in connection with the original permitting of the facility. The commenters claimed that the District cannot issue an amended PSD Permit because there is no existing permit to amend. They claimed that the District needs to treat this application as a new permit application.

[383] The lengthy and detailed comments submitted by Mr. Simpson, as well as many other commenters, emphasize the extent to which members of the public were able to inform themselves regarding this permit based on the documentation and analysis the Air District published and made available.

Response: The commenters are correct that when the facility was initially permitted in 2002, the District did not issue a final Federal PSD permit when it issued its Authority to Construct, as is the District's normal practice. The record indicates that the District did not finalize the Federal PSD permit at the time it issued the Authority to Construct because EPA Region IX had not completed its ESA consultation with the US Fish & Wildlife Service. The project applicant subsequently withdrew its plans to build the facility at the original location, however, and so the consultation was never finalized and the Federal PSD Permit was never issued.[384]

As a substantive matter, however, the Air District did treat this permit application substantively as a new permit rather than as an amendment, as the comments suggest it should have. In evaluating the project for compliance with Federal PSD requirements, the Air District did not rely in any way on the analysis prepared for initial permit. To the contrary, the Air District made clear in the Statement of Basis that it was evaluating the entire project for compliance with the Federal PSD requirements, not just elements that were changing since the initial permitting. As the Air District explained in the Statement of Basis, it analyzed both the amendments to the proposed project as well as the elements that were not being changed, and concluded "[t]he analysis of the elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standard for Federal PSD Permit, and that they would *comply with current PSD requirements even if they were being proposed anew at this time*." (Statement of Basis at p. 7 (emphasis added).) The detailed analyses provided in the Statement of Basis clearly support this conclusion. The Air District evaluated all of the equipment at the project from scratch to ensure that it meets current BACT standards as is required for a new permit application. The District similarly conducted an Air Quality Impacts Analysis (and related analyses) from scratch for the entire project, using the most current information and modeling techniques, as is required for a new project. The Air District's review of this project was therefore effectively a new permit evaluation, even if it was erroneously referred to in the initial Statement of Basis as a revision to an existing permit.

Furthermore, the Air District clarified this situation in the Additional Statement of Basis and corrected its earlier misstatements, and made clear that it was proposing to issue the permit as a new permit and not as an amended permit. The Air District specifically invited members of the public who had initially believed that this would be an amendment to an existing permit to provide any comments they may have on the issuance of a new permit, as opposed to an existing permit, during the second comment period. The Air District therefore agrees with the comments that it should treat this permit as a new permit, and responds that it has fully treated it as a new permit.

Comment XVII.E.2. – Changes to Federal PSD Permit Since 2007:

The Air District received comments questioning whether there have been applicable permitting rules that have changed since the issuance of the state-law permits in 2007 or whether there have been refinements to the technical analyses of the facility since that time.

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[384] *See* Letter from Gerardo C. Rios, Chief, Permits Office, U.S. EPA Region IX, to Ryan Olah, Chief, Endangered Species Division, U.S. Fish and Wildlife Service, June 11, 2007, subject; Request for Informal Consultation under Section 7 of the Federal Endangered Species Act for the Proposed Russell City Energy Center – Hayward, California, pp. 1-2.

Response: This comment appears to refer to any ways in which the Air District has expanded upon or revised any elements of its analyses underlying the Draft Federal PSD Permit since its earlier analysis in 2007 on which the PSD Permit was initially issued. The Air District responds by referring to the specific analyses set forth in the Statement of Basis and Statement of Basis and this Response to Comments document, which represent the Air District's most current analysis of the applicable Federal PSD Requirements. The Air District is issuing the Federal PSD Permit based on the most current regulatory requirements and the most current technical analyses.

XVIII. STATE-LAW LICENSE/PERMIT ISSUES

The Air District also received a number of comments regarding the CEC's license for this project, the Air District's Authority to Construct,[385] and other California state-law requirements such as the provision of Emission Reduction Credits and compliance with the California Environmental Quality Act ("CEQA"). These state-law issues are not part of the Federal PSD Permit review process, and the Air District therefore has no obligation to consider and respond to them as they do not pertain to PSD permit issuance. The Air District nevertheless has reviewed and considered them since members of the public have expressed an interest in them, and the District responds to them in this section.

Comment XVIII.1. – Reopening State-Law Permitting Proceedings:

The Air District received comments contending that it should 'withdraw' the Determination of Compliance that it prepared for use by the CEC in the CEC's licensing proceeding for the Russell City Energy Center under California's Warren-Alquist Act. Some of these comments argued that the Determination of Compliance the Air District provided for the CEC's use in that proceeding needs to be re-analyzed and re-issued to reflect the Air District's subsequent analyses such as those that the Air District has undertaken in this PSD permit proceeding. Some comments stated that there have been new scientific and regulatory developments since the CEC licensing proceeding took place, such as $PM_{2.5}$ and CO_2 regulatory developments and new scientific study on the effects of $PM_{2.5}$. Some of the comments also challenged the validity of the state law approvals the project has received, and suggested that a Federal PSD permit may not be issued unless it can be shown that the project complies with state law. These comments suggested that the Air District should conduct a further Determination of Compliance proceeding and solicit comments on state-law issues as well as on Federal PSD issues. Some comments claimed that the Determination of Compliance process and PSD Permit process are interdependent, and that if the Federal PSD permit process is reopened for additional public comment then the Determination of Compliance process must also be reopened. Some comments claimed that the District cannot issue a Determination of Compliance concluding that the project will comply with Federal PSD requirements until after the Federal PSD permitting process is complete.

Response: How the project complies with state-law requirements and how the CEC's licensing process was conducted are not issues that are implicated by the Federal PSD Permit requirements. These comments therefore do not raise issues relevant to the Air District's determination on the Federal PSD permit. To the extent that the commenters have any concerns about potential defects in the CEC licensing process that should be revisited at this point, those concerns should be addressed to the CEC directly, not in a PSD permit proceeding.

With regard to the Determination of Compliance that the Air District prepared for use by the CEC in its licensing proceeding, that document is not something that can be withdrawn or

[385] The Authority to Construct is the District's Non-Attainment NSR Permit issued under state law pursuant to the District's SIP-Approved Non-Attainment NSR permit regulations, District Regulation 2, Rule 2.

vacated at this point. That Determination of Compliance was submitted to the CEC by the District in 2007, and it was then used by the CEC in its licensing proceeding, which culminated in a commission licensing decision, which has long been final and all avenues for appeal have been exhausted. The time for raising any concerns with the District's 2007 Determination of Compliance came and went long ago. To the extent that these comments suggest that events that have taken place since the CEC proceeding in 2007 have raised new or changed issues that should be revisited and further analyzed at this time, these comments should be directed to the CEC. If the CEC determines that these claims have merit and decides to undertake further proceedings, the Air District would be happy to participate in any such proceeding at the request of the CEC.

Regarding the interdependence of the Federal PSD Permit and the state-law licensing process under the Warren-Alquist Act, although the state and federal permitting mechanisms overlap, they are legally distinct and do not depend on each other. The fact that the Federal PSD Permit was remanded by the EAB did not invalidate the state-law licensing, in the same way that the California Supreme Court's upholding of the CEC's licensing decisions did not validate the Federal PSD permit. The Air District therefore disagrees with the comments stating that the Air District must reopen the state-law permitting proceedings because of the Federal PSD remand and that the Air District cannot issue a Determination of Compliance until after the Federal PSD permitting process is complete.

Comment XVIII.2. – Expiration of Authority to Construct:

The Air District also received comments stating that it should rescind the Authority to Construct because it is no longer valid. Some of the comments claimed that the Authority to Construct has become invalid by operation of 40 C.F.R. § 51.166(j)(4) on the grounds that the Authority to Construct was issued over 18 months ago.

Response: 40 C.F.R. Section 51.166 contains requirements for state Non-Attainment NSR Permitting programs generally. The requirements in that section do not apply to specific permits issued for particular projects such as the District's Authority to Construct for the proposed facility here.[386] The expiration of the District's Authority to Construct is governed by District Regulation 2-1-407, which provides that the Authority to Construct expires after two years. Two years have now passed since the Authority to Construct was issued, and so the project owner has applied to the Air District for an extension of that Authority to Construct. The Authority to Construct extension will also implicate the CEC license provisions, and the Air District will participate in any CEC license proceeding as requested by the CEC. These issues regarding the District's state-law Authority to Construct and the CEC's license under the California Warren-Alquist Act are not Federal PSD issues, however, and do not implicate the Federal PSD permit that the District is issuing.

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[386] Some of the comments also cited other authorities relevant to the expiry of PSD permits (as opposed to Nonattainment NSR permits). The PSD permit is being initially issued concurrent with these Responses to Comments, and so its period of validity (18 months) is only just beginning now. It has therefore not expired under any view of the law, and the authorities regarding expiration of a PSD permit are not relevant here in the context of arguments about the expiration of the Authority to Construct.

Comment XVIII.3. – Non-Attainment NSR Permitting:

The Air District received several comments regarding its Non-Attainment NSR permitting for the facility. Some comments stated that the District's BACT analysis was inconsistent with the District's BACT approach under its Non-attainment NSR rules (District Regulation 2-2) and under the federal Clean Air Act and EPA's implementing regulations for Nonattainment NSR. These comments claimed that the District needs to conduct further Nonattainment NSR review and analysis for the project for NOx, CO and $PM_{2.5}$. The comments objected to the Air District's position that the Non-Attainment NSR permit – the Authority to Construct – is final and is not being reopened in the PSD permitting action. Some implied that the Authority to Construct was invalidated by the remand of the Federal PSD permit. Some comments questioned whether avenues for appealing the Authority to Construct have in fact been exhausted.

Response: Non-Attainment NSR is a state-law permitting program conducted in accordance with the District's SIP-approved Non-Attainment NSR regulations. It is a separate permitting program and is not part of the Federal PSD permitting process. The Non-Attainment NSR permitting process, and the Authority to Construct that was issued at the culmination of that process, has been completed and is now final as discussed above. The Air District therefore disagrees that it can or should conduct further Non-Attainment NSR permitting analyses. The Air District has already completed the Non-Attainment NSR permitting analysis for NOx and CO, and for $PM_{2.5}$ the facility is exempt from Non-Attainment NSR permitting under 40 C.F.R. Part 51, Appendix S, as discussed in Sections VI and XIII above. Moreover, Non-Attainment NSR permitting is separate and distinct from PSD permitting and is subject to different regulatory requirements under different legal authority, so Non-Attainment NSR issues are not relevant to the Federal PSD Permit in any event.

Comment XVIII.4. – NO_2 Impacts and Compliance With California Ambient NO_2 Standard:

The Air District received comments regarding whether the project's NO_2 emissions, in addition to background concentrations, would cause an exceedance of California's new NO_2 standards. The comments noted discrepancies among some of the permitting documents wherein the District's current estimates indicate that project impacts plus background will not cause an exceedance of the California NO_2 standard, but earlier estimates had shown levels above the new NO_2 standard. The comments claimed that the Air District's current position is was not adequately explained, and stated that the District should provide a full analysis demonstrating compliance with the CA NO_2 standard as part of the PSD permit process.

Response: California NO_2 standards are not incorporated in the Federal PSD Permit requirements. For Federal PSD purposes, the facility is required to demonstrate that it will not cause or contribute to a violation of the Federal NAAQS for NO_2 (among other requirements). That demonstration was made in the Air Quality Impact Analysis for this project, and the Air District did not receive any comments suggesting that the NO_2 element of that analysis was incorrect.

The District notes, however, that although the California NO_2 standard is not part of the Federal PSD permitting process, it is an important air quality standard that was addressed as part of the state-law permitting review for the facility. The project's NO_2 impacts were analyzed in the state-law permitting process, and the analysis found that the proposed facility will not cause an exceedance of the new California NO_2 standard. The analysis showed that the maximum potential NO_2 impact from the project will be 130 $\mu g/m^3$. When added to background concentrations of 130 $\mu g/m^3$, total concentrations will be less than new California standard of 338 $\mu g/m^3$. The reason for the discrepancy noted between this analysis and earlier estimates of NO_2 impacts is that earlier NO_2 modeling was performed using the model ISCST. EPA has made that model a non-guideline model and it has been replaced with the AERMOD, the current EPA guideline model. While previous modeling was performed while ISCST was the guideline model, the results presented in this analysis are made with AERMOD. The Air District published this further information and explanation in the Additional Statement of Basis (*see* pp. 83-84) and did not receive any further comment during the second comment period.

Comment XVIII.5. – Compliance with CEC and Authority to Construct Monitoring Requirements:

The Air District received comments noting a condition of the Authority to Construct regarding the installation of equipment for emissions monitoring and questioning whether this or other conditions of the Authority to Construct have been completed yet.

Response: The applicant has not commenced construction at this time, and so the Air District does not believe that these conditions have been completed at this time. In particular, the facility has not yet been built and so there is nothing to install the monitoring equipment on. The applicant will become subject to these conditions at the appropriate time as it goes forward to build and operate the facility. This comment does not appear to refer to anything relevant to the Federal PSD permit requirements.

Comment XVIII.6. – Compliance with CEC Condition AQ-SC10:

The Air District received comments questioning whether the District has complied with Condition AQ-SC10 of the CEC's license, and whether the District could be compelled to comply with this condition.

Response: Conditions in the CEC license apply to and are binding on the project owner, not on the District. Since the District will not be building or operating the facility, the District cannot comply with this condition, which by its terms is inapplicable to the District. For the same reasons, the District could not be compelled to comply with the condition. Moreover, the condition allows an optional alternative for the facility in lieu of satisfying other conditions of certification, and so it does not appear that even the project applicant could be compelled to comply if it chose not to select this alternative. The condition will simply authorize alternative ways to comply with the license, not mandate that the facility utilize any of the alternative means of compliance. And finally, conditions in the CEC license are state-law requirements and are not a part of the Federal PSD permitting process. For all of these reasons, the Air District finds nothing in these comments that is relevant to the Federal PSD permit requirements.

Comment XVIII.7. – California Environmental Quality Act Issues:

The Air District received several comments regarding the facility's compliance with CEQA. Some comments suggested that the issuance of a federal PSD Permit is subject to CEQA, and requested that the District process the Federal PSD permit consistent with the requirements of CEQA. Some comments also implied that the CEC can no longer be the CEQA lead agency for the project since that agency's permitting action was completed, and its permit record closed, some time ago. Some comments cited CEQA Section 15154 to suggest that the District should assess airport impacts and air-quality impacts to in-flight receptors. Other comments criticized the CEC CEQA-equivalent environmental review process as a poor substitute for CEQA, and also criticized the way the CEC has handled its environmental review responsibilities for this facility, in particular with respect to sensitive species issues. Some comments stated that the District had properly relied on the CEC's CEQA-equivalent environmental analysis in its state-law permitting actions in 2007, but claimed that the Air District should conduct additional CEQA analysis before issuing the Federal PSD permit. These comments claimed that the project has changed since it was approved by the CEC and that the Air District should therefore undertake additional CEQA analysis at this point as part of the Federal PSD permitting process.

Response: The issuance of a Federal PSD permit is not subject to CEQA. The Federal PSD Permit is a federal permit issued under the federal Clean Air Act and is not an action taken pursuant to California law. CEQA applies to this facility through the California Energy Commission licensing process, which includes a thorough environmental impact analysis that is the equivalent of the CEQA environmental impact analysis process. The Commission undertook that analysis, which included many public hearings and the review of a large amount of evidence and testimony regarding a broad range of potential environmental impacts. As a result of the comprehensive review, the CEC found that, with the required mitigation, there will be no significant environmental impacts.[387] The project has therefore fully complied with all CEQA requirements, and so CEQA would not provide grounds to object to the project even if CEQA were something that is required for issuance of a Federal PSD Permit.

Comment XVIII.8. – Emissions Offsets and ERCs Identified in the Determination Of Compliance:

The Air District received comments questioning whether the facility's use of emission reduction credits to satisfy its Non-Attainment NSR emissions-offsetting obligations complies with Federal PSD permitting requirements, and whether doing so will protect air quality. In particular, these comments questioned whether the credits used should have been generated in the same location as the facility and whether they are sufficiently "contemporaneous" to satisfy the Non-Attainment NSR emissions-offsetting requirements. Some comments also claimed that the facility will be providing 134.6 tpy of NO_2 Emission Reductions Credits, but that this amount will not be sufficient to offset the emission increases from the project. These comments divided the total offsets by 365 to create a "daily" offset amount, and noted that this is lower than the daily emissions limit in the permit. Finally, some comments also questioned whether some of the credits identified in certain permit documents were validly created. They noted that certain information regarding the background of one of the ERC banking certificates is not available, and questioned why some of the specific credits identified for the facility are different than those identified in the CEC decision. Some comments claimed that some ERCs identified for this project have already been pledged to another Calpine project.

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[387] *See* 2007 Energy Commission Decision, *supra* note 16, p. 2 finding 3.

Response: Emission offsets are not a part of the Federal PSD Permit; they are required under State law under the District's non-attainment NSR permit program. The Environmental Appeals Board expressly stated that offsets and Emission Reduction Credits are a "Non-PSD Issue" and not something that the Air District is required to address on remand. (*See* Remand Order, Slip. Op. at pp. 39-40 ("ERCs are a product of District Regulation 2-2-302, and thus a California state law, not a federal PSD requirement.").) The commenters' concerns about the provision of ERCs therefore do not implicate any Federal PSD Permit issues.

The commenters should rest assured that the ERCs for this facility satisfy all requirements of the District's NSR permitting program under state law, however. The Air District's offset and ERC requirements in its NSR Rule require that new facilities of more than a certain threshold size obtain offsets from reductions of other sources to counterbalance new emissions from the new facilities. In appropriate circumstances, the new facilities are required to obtain more offsets than the new emissions they will cause. In this way, new development can go forward while still ensuring consistency with the Bay Area's goals of meeting all ambient air quality standards. The Air District's rules allow facilities to use credits generated by reductions at facilities that have previously shut down to offset new emissions. This allows some flexibility where old facilities are not shutting down at the exact point in time when new facilities are starting up, but it still achieves the same air quality benefits because the emissions reductions from a closed facility have the same effect going forward regardless of whether the facility closed in 2010 or in some earlier year. The Air District's rules also allow the use of reduction credits that may not have occurred at the exact same location as the new facility as long as they are from within the Bay Area region. Again, this allows for some flexibility where there are no existing facilities being shut down at the exact site of a new project, but is still consistent with the goals of achieving compliance with region-wide air quality concerns. The Air District's rules have been reviewed by the US Environmental Protection Agency and have been approved as consistent with the requirements of the federal Clean Air Act.

As the Air District has determined in its permitting analysis regarding the Non-Attainment NSR permitting for this facility, the Russell City Energy Center is subject to the offset/ERC requirements in the Air District's NSR Rule (Regulation 2, Rule 2), and will submit ERCs sufficient to offset its new emissions as required by that Rule. The commenters correctly note that for NOx these ERCs will offset the facility's new emissions in the amount of 134.6 tons per year. There is no "daily" offset requirement, however, as it would be unworkable to require facilities to find offsets from facilities that have shut down that exactly matched the new facilities' daily emissions profile. For example, for a factory that operates 5 days a week and is shut down on weekends, it would be unworkable for it to have to find credits from another facility that operated on the same daily schedule to ensure that daily emissions are offset. And such daily matching is not necessary to ensure the air quality goals of the region-wide offset program, as on a regional basis the variations in daily operating scenarios of specific facilities will average out over the region as a whole to ensure a general decline in total emissions on a daily, weekly, monthly and annual basis.

Furthermore, the facility has identified sufficient ERCs to satisfy its offset requirements. Some older documents may include outdated information regarding the ERCs to be used for this facility because the Air District authorized the applicant to swap certain ERCs between Russell

City and another plant in 2007. The swap replaced ERC Certificate No. 815, which was generated in Hercules, with certificates Nos. 602, 687, and 877, which were generated in Oakland, San Leandro, and Hayward, respectively. Although the credit from Hercules was useable at Russell City because both locations are within the same Air District, this swap resulted in the use of credits at Russell City that were generated even closer to the location of the new facility's emissions. In addition, although certain information about the creation of one of the credits may not be available at the current time, that does not mean that the credit is invalid for offsetting purposes. ERCs are subject to careful scrutiny when they are created, and when they are approved they are recorded in the Air District's offsets "bank". At that point a "certificate" is created to track the offsets, and that certificate must be surrendered when the credit is used (and the certificate is canceled so the credit cannot be used again elsewhere). The submission of the certificate from the bank will ensure that the credit being provided represents real emission reductions generated by shutting down another facility elsewhere in the region in an amount represented by the certificate, even if the exact details of the facility that was shut down are not known.

XIX. OTHER ISSUES NOT RELATED TO FEDERAL PSD PERMIT REQUIREMENTS

The Air District also received a large number of comments relating to issues or legal requirements that are not part of the Federal PSD program and are thus not part of the Air District's review of the proposed facility. Since such issues are not a part of Federal PSD permitting, these comments have no bearing on the Air District's determination with respect to this permit. The Air District appreciates the public's interest in these issues, however, and agrees that many of the comments touch on important aspects of the project, albeit ones that are addressed under different regulatory regimes. The Air District is therefore responding to these public comments, even though they are unrelated to the Federal PSD permit.

Comment XIX.1. – Endangered Species Act:

The Air District received comments suggesting that the facility could adversely impact endangered species, in particular through impacts on wetland areas near the facility. Some comments stated that the District must refrain from issuing a final PSD permit until the Fish & Wildlife Service ("FWS") has determined that project will not adversely affect any endangered species. Some comments claimed that a full Biological Opinion by the FWS is required to ensure the protection of sensitive species and their habitats, which they claimed would be significantly and negatively affected by the facility. The comments specifically cited potential nitrogen deposition impacts, noise impacts, and acid rain impacts as potentially harmful to sensitive species and their habitats. Some comments also stated that the Air District will need to conduct an analysis of the impacts of CO_2 emissions on particulate matter and ozone levels in order for EPA and FWS to conduct their Endangered Species Act consultation and review.

Response: The Endangered Species Act review for this project is not directly a part of the Federal PSD Permit process. EPA must of course comply with its ESA obligations before the permit becomes final, but that is a separate legal requirement from the PSD permitting process. (*See* Remand Order at pp. 40-41.) The Air District is therefore not required to respond to comments on ESA issues – those comments should be directed to EPA Region 9.

Endangered species issues are obviously important, however, and the Air District has been cooperating with EPA Region 9 to assist in ensuring that endangered species issues are fully addressed. EPA and FWS have conducted a comprehensive analysis of endangered species concerns here as part of their consultation and ESA review, which took into account all potential impacts from the facility on sensitive species and their habitats. FWS and EPA have concluded that the project will not likely adversely affect any endangered species or their critical habitats.[388] Based on the findings by these two expert agencies, the Air District disagrees that the facility will have any adverse impacts on endangered species or their habitats.

Comment XIX.2. – National Environmental Policy Act:

The Air District also received comments asking whether the proposed permit complies with the federal National Environmental Policy Act ("NEPA").

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[388] *See* EPA ESA Consultation Letter, *supra* note 341; USFWS ESA Consultation Letter, *supra* note 341.

Response: EPA has made clear that PSD Permits are not subject to the environmental impact statement provisions of NEPA.[389] Issuance of the Federal PSD permit does not violate NEPA because the statute is inapplicable. The project is subject to a CEQA-equivalent review under state law, however, which is at least as thorough and rigorous as a NEPA analysis. The potential for environmental impacts from the project has been studied in great detail, and with the mitigation that will be required there will be no significant environmental impacts.

Comment XIX.3. – Other Federal Statutes:

The Air District received comments suggesting that the facility may be inconsistent with statutes such as the Coastal Zone Management Act, the Clean Water Act, the Migratory Bird Treaty Act, the Magnus-Stevens Act, and other federal statutes in general.

Response: The PSD Permit ensures compliance of the proposed facility with the PSD provisions of the Clean Air Act. To the extent that other statutory provisions apply to the facility, compliance is ensured through the compliance mechanism specific to those statutes, not through PSD permitting. For example, as noted above ESA compliance is ensured through consultation between EPA and the US Fish & Wildlife service and is not a part of the PSD permit process (although the ESA consultation process can be useful in informing the PSD air quality impact analysis, as happened here). Similarly, to the extent that the project implicates any CWA issues, compliance would be ensured through the CWA permitting processes. These additional statutes are not part of the Air District's PSD permit review. (*See* Remand Order at p. 41.)

The Air District notes that the comments did not identify any areas in which these other statutes impose any applicable requirements on the proposed facility, or that construction of the facility would be inconsistent with any of these other statutes, and the District is not aware of any way in which the facility would be inconsistent with any applicable requirements under these statutes. But even if the comments had identified some way in which the facility would be inconsistent with an applicable provision of these statutes, the appropriate avenue to address such issues would be through the appropriate permitting provisions of those statutes (or other applicable avenues provided by those statutes to ensure compliance). Potential inconsistency with any of these statutes (to the extent any existed) would not be a reason to modify or deny the federal PSD permit here, and the comments have not stated any reason why the District should do so based on these statutes.

Comment XIX.4. – Coastal Management Concerns:

The Air District received comments suggesting that issuance of a Federal PSD permit would be inconsistent with the San Francisco Bay Coastal Management Program Assessment and Strategy and the homepage of the NOAA Office of Ocean and Costal Management.

Response: Again, to the extent that there are legal requirements applicable to this facility under statutes addressing coastal management issues, those concerns would be addressed directly under

[389] *See* 40 C.F.R. § 124.9(b)(6); *see also, e.g.*, *In re Knauf FiberGlass, GmbH*, 8 E.A.D. 121, 171 (EAB 1999); *In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 129 (EAB 1997).

the applicable regulatory program. Coastal management concerns are not part of the Federal PSD permit program. Moreover, the comments did not identify any specific regulatory requirements regarding coastal management issues that the facility may not be complying with, and the Air District is not aware of any. For all of these reasons, there is nothing in these comments suggesting that the Federal PSD permit should not be issued.

Comment XIX.5. – National Register of Historic Places:

The Air District received comments claiming that salt ponds near the proposed facility's location are a rural historic landscape. The comments suggested that the facility would not be consistent with the National Register of Historic Places.

Response: Concerns about impacts to historical resources are addressed through mechanisms such as the CEC's CEQA-equivalent environmental review process, and not through the federal PSD permitting process. Historic resource concerns are not part of the Federal PSD permit program. Moreover, the comments did not identify any specific regulatory requirements regarding historical resource issues that the facility may not be complying with, and the Air District is not aware of any. For all of these reasons, there is nothing in these comments suggesting that the Federal PSD permit should not be issued.

Comment XIX.6. – Hazardous Air Pollutant (HAP) Emissions Under CAA Section 112:

The Air District received comments suggesting that it has failed to take into consideration MACT standards for Hazardous Air Pollutants ("HAPs") pursuant to Section 112 of the Clean Air Act, 42 U.S.C. section 7412. The comments stated that the Air District has not determined how much HAPs the facility may emit, and so it is impossible to determine if the facility will be subject to the Section 112 MACT standards. The comments stated that the Air District must address Section 112 compliance as part of the PSD Permit review.

Response: The review of MACT requirements under Section 112 of the Clean Air Act is a separate requirement from the Federal PSD requirements under Section 165 of the Clean Air Act. Per Section 112(b)(6), Section 112 Hazardous Air Pollutants are specifically exempt from PSD permitting under Section 165. For this reason, Section 112 MACT review is not normally undertaken within the context of a Section 165 PSD permitting proceeding. But regardless of whether Section 112 MACT issues need to be addressed as part of the Federal PSD permit review, the issue is irrelevant here because the facility is not subject to MACT requirements under Section 112. The facility will not emit more than 10 tons of any Section 112 HAP or 25 tons of all HAPs combined.[390]

Comment XIX.7. – 40 C.F.R. Section 60.11(d):

The Air District received comments stating that 40 C.F.R. section 60.11(d) was not specifically addressed in the permit conditions. This regulation is a general New Source Performance Standard ("NSPS") general provision requiring that affected sources, including air pollution

[390] *See* December 8, 2008, Statement of Basis at pp. 14-15, Table 6. Note that ammonia, which is listed in Table 6 and was included in the Air District's Health Risk Assessment, is not a Section 112 Hazardous Air Pollutant. *See* CAA Section 112(b)(1); 40 C.F.R. § 61.01.

control equipment, shall to the extent practicable be operated and maintained in a manner consistent with good air pollution control practice for minimizing emissions.

Response: The applicability of NSPS requirements to this facility was addressed in the December 8, 2008, Statement of Basis (*see* p. 65). To the extent that this general NSPS requirement is relevant to the PSD review as an applicable emissions standard or standard of performance, the facility will be required to comply with it through the applicable permit conditions requiring emissions to be minimized to the greatest achievable extent as discussed in the various BACT analyses for the project. Air pollution control equipment that the facility will use to comply with these requirements (*e.g.*, the SCR system) will have to be operated and maintained in a manner consistent with good air pollution control practice in order to keep the facility's emissions within these limits. The comments did not identify any information to suggest that the facility will not comply with the requirements of 40 C.F.R. section 60.11(d), and the Air District is not aware of any. The Air District has therefore concluded that the facility will comply with this requirement, to the extent that it is an applicable requirement for purposes of PSD review.

Comment XIX.8. – Noise Impacts:

The Air District received comments claiming that noise from the facility could harm sensitive species and habitats in the vicinity of the project.

Response: Noise is not one of the environmental impacts that is addressed through the Federal PSD program as it is not related to air pollution or air-pollution related concerns like soils and vegetation impacts. Noise concerns are important, but they are addressed through other mechanisms such as the Energy Commission's CEQA-equivalent environmental review. With respect to potential noise impacts on endangered species, those concerns are also addressed under the Endangered Species Act and in the case of this facility through the Endangered Species Act consultation process between EPA and the Fish & Wildlife Service ("FWS"). Here, FWS considered information provided by the applicant concerning noise impacts from the project and, as a result of EPA's informal consultation, the applicant has agreed to submit the Construction Noise Mitigation Plan required by the Energy Commission license to FWS.[391] The FWS has concluded that noise levels from the project, both from construction and operations, will not adversely affect any sensitive species or critical habitat.[392]

Comment XIX.9. – Potential Hazards to Aviation:

The Air District received comments expressing concern about the potential for thermal plumes and pollutant emissions from the facility to impact aircraft and aircrews and passengers. The comments claimed that these concerns will limit airspace use around the facility, which they claim is already limited by a number of factors. The comments claimed that the CEC's staff

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[391] *See* Letter from Barbara McBride, Director, Environmental Health and Safety, Calpine Corporation, to Weyman Lee, P.E., Senior Air Quality Engineer, Air District, June 26, 2009, re: Submission of Supplement to Russell City Energy Center's Application for Prevention of Significant Deterioration Permit to Require Approval of Certain Construction Plans by U.S. Fish and Wildlife Service.

[392] *See* USFWS ESA Consultation Letter, *supra* note 341, at p. 3.

recommended against approving the proposed facility based on aircraft hazard concerns. Another commenter supported the project and stated that there would be no adverse impacts to aircraft or airport operations.

Response: The Federal PSD Program is designed to address certain air quality issues, not to address safety issues such as potential hazards to aviation and aircraft operations. Safety issues such as these are obviously a very important public concern and there are comprehensive regulatory requirements in place to address them, but the Federal PSD Permit is not the mechanism to do so. Such concerns could potentially have an impact in a Federal PSD BACT analysis if there was a choice between alternative control technologies that had greater or lesser safety impacts, but that is not the case here. None of the comments has provided any information to suggest that different control technologies should be used or that permit conditions should be changed based on the potential for aviation hazards.[393]

Moreover, the potential for aviation hazards was examined in detail by the Energy Commission during the licensing proceedings for the facility. The Commission reviewed a sophisticated analysis of vertical plume velocities and a 2006 FAA study entitled "Safety Risk Analysis of Aircraft Overflight of Industrial Exhaust Plumes", and concluded that the FAA would characterize this risk as extremely remote and within acceptable ranges. The Energy Commission therefore found that the impact from potential aviation hazards would be less than significant.[394] The Energy Commission similarly found that restrictions on airspace as a result of the facility would be less than significant. While it may be true that CEC staff recommended against the project because of aviation issues, the Commission disagreed and concluded that these were not significant concerns because they could be mitigated, as recommended by the FAA, by pilot notification, among other reasons. This considered analysis by the Energy Commission is how such issues are addressed, not through the Federal PSD program.

<u>Comment XIX.10. – Impacts To Operations at Area Airports:</u>

The Air District received comments claiming that the facility would not be compatible with local airport operations, including Oakland International Airport and in particular Hayward Executive Airport. The comments cited commitments made by the City of Hayward to remove and mitigate airport hazards and to ensure compatible land uses around the airport. The comments requested that the FAA evaluate the economic impacts of the facility on the Hayward Executive Airport and other airports in the region. The comments also suggested that the FAA, CEC and California Department of Transportation should develop guidelines for assessing power plant siting near airports, rather than addressing the issue on a project-by-project basis. Another commenter supported the project and stated that there would be no adverse impacts to aircraft or airport operations.

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[393] Note that the Air District addressed concerns about ammonia emissions on air crews and passengers, which was relevant to the selection of SCR as the NOx control technology, in Section IV above and found that it would not have any significant impacts that could affect aviation. The Air District also addressed the issue of toxics emissions generally in Section XIV and found that they would not cause any significant health risks to air crews or passengers.

[394] *See* 2007 Energy Commission Decision, *supra* note 16, at pp. 179-88.

Response: The Federal PSD Program is designed to address certain air quality issues, not to address issues regarding the compatibility of different land uses. Those types of issues are considered by the Energy Commission in its siting decisions were it determines the location of and need for new power generation facilities. The Air District would support the development of guidelines for power plant siting near airports to help in siting decisions, but such issues are not related to Federal PSD permitting.

Comment XIX.11. – Generalized Support For and Opposition To Project:

A number of commenters simply stated that they are opposed to the project, without stating any way in which the project would be inconsistent with the Federal PSD Requirements. Some stated that they opposed new power plants such as this, and some stated that no new fossil-fuel fired facilities should be built. Some stated that they were not necessarily opposed to new fossil-fuel fired power plants, but that they should not be sited at this location. Some stated simply that they want the Air District to deny the PSD permit for this facility. In addition, the Air District also received a number of countervailing comments supporting the siting of facility at this location.

Response: The Air District defers to the Energy Commission regarding what types of electrical generating capacity should be provided at what locations to best serve California's electrical grid. The Air District therefore refers commenters who are generally unsatisfied with the decision to site a power plant at this location, or to license a fossil-fuel-fired plant at a time when renewable electricity sources have received renewed emphasis, to the Energy Commission. The Air District's role in the approval process for new power plants is to review them to ensure that they will comply with all applicable air quality regulatory requirements if the Energy Commission approves them. The Air District has done so here with respect to the Federal PSD requirements and has found that this facility will satisfy all such requirements and is eligible for a Federal PSD Permit.

Comment XIX.12. – Project Aesthetics:

Some comments objected to the facility on generalized aesthetic grounds, suggesting that the facility would not fit in with the surrounding visual background.

Response: Project aesthetics are not part of the Air District's review for the Federal PSD Permit. Local land use concerns such as this should be addressed to the City of Hayward, and to the CEC which has approved the siting of the facility at this location.

Comment XIX.13. – Need for the Project:

The Air District received comments questioning whether the facility was really needed to provide power for the Bay Area. Some comments suggested that the need for power was on the West side of the San Francisco Bay, and that the facility should not be built on the East side to serve this demand. Some comments suggested that assertions about the demand for electricity are part of a "scam" and are not true. Some comments suggested that an increase in demand should be met with measures to decrease demand, not with an increase in supply. Some suggested that an increase in demand should be met through conservation or cleaner sources. Some comments suggested that if this facility is built it will prevent 600 MW of renewable power from being developed.

Response: The demand and supply of electricity in California is overseen by other expert agencies such as the California Energy Commission, the California ISO, and the California Public Utilities Commission. The Air District defers to the judgment of expert agencies such as those in determining how demand will be met and what new generating capacity is needed and how it should be provided. The Air District therefore does not take a position on the need for this facility and whether this facility is the most appropriate way to meet that need. But in any event, these issues are not directly related to air quality and whether the facility will meet applicable air quality-related regulatory requirements, and are not relevant to the PSD permitting analysis.

Comment XIX.14. – Use of New Facility to Replace Older Facilities:

The Air District received several comments regarding a statement in its Associated Growth analysis that electricity from the proposed facility will displace power from older, less efficient sources of electricity elsewhere in the region. These comments criticized this statement because they claimed that the District does not have any decision-making authority over closing old power plants and cannot know for certain whether older facilities will be shut down as a result of this new facility (and if so whether they will be in the same area as the new facility). The comments stated that the Air District should take steps to ensure that the public does not misunderstand the District's role in deciding whether to close older facilities. In contrast to these comments, the Air District also received other comments that supported the Air District's statement and asserted that the addition of the facility will allow older plants to be taken off-line.

Response: The Air District agrees that it does not know for certain whether older facilities will be able to be shut down as a result of the new Russell City Energy Center. The Air District made the statement that is the subject of these comments because, in general, it expects that at least some of the additional capacity from this facility will be used to take the place of older facilities. But the extent to which this facility will replace existing facilities (if at all) is not relevant to the Federal PSD requirements, and so it makes no difference to the Air District's permitting decision which position is correct. Nothing in the Federal PSD regulations makes the issuance of a permit for a new facility contingent on closing down an older facility.

Moreover, the Air District also notes that the CEC recently decided that, because of the unique nature of how power plants are dispatched as part of an integrated grid system, the greenhouse gas emissions from a proposed power plant should be assessed on a system-wide basis for purposes of CEQA.[395] Importantly, the CEC found that, because a plant's position in the dispatch order is determined by its "heat rate", which is, in turn, "directly correlated with emissions (including GHG emissions), *when one power plant runs, it usually will take the place of another facility with higher emissions that otherwise would have operated*."[396] Thus – in the case of a similar facility with similar intended dispatch to the applicant's proposed Russell City Energy Center and a similar "heat rate" – the CEC found that operation of the facility would, in

[395] Avenal Energy Commission Decision, *supra* note 58, at pp. 103-104, 113 ("The GHG emissions from a power plant's operation should be assessed in the context of the operation of the entire electricity system of which the plant is an integrated part.").

[396] *Id*., p. 104, emphasis in original.

fact, take the place of a less efficient plant and thereby result in system-wide reductions in emissions, even if the less efficient plant would remain in service and not be permanently decommissioned as a result of the new facility's operation.[397] While the extent to which the proposed facility might replace older plants is not germane to the Air District's decision concerning issuance of the PSD permit, the District notes that the CEC's decision would tend to support that addition of a highly efficient plant such as the proposed Russell City Energy Center to the grid is likely to lead to a reduction in the operation of older, higher polluting plants and, as a consequence, in system-wide emissions.

Comment XIX.15. – Alternatives to the Project:

The Air District received comments claiming that it should consider other alternatives to the project, such as solar power or reducing demand so that the facility would not have to be built.

Response: As noted elsewhere in this Response to Comments document, the Federal PSD Permit analysis does not evaluate alternatives that would "redefine" the project by changing its fundamental purpose and basic design. This means that the Federal PSD Permit review does not look at alternatives such as solar power, demand management, or other similar alternatives. That does not mean that such considerations are unimportant, however, and they can appropriately taken into account in the overall permitting of the facility. But this type of review of alternatives is undertaken in other forums such as the CEC's CEQA-equivalent environmental review process, not through the Federal PSD permitting process.

Comment XIX.16. – Job Creation:

Some comments supported the project because it will create jobs for the construction workers who will build the facility and the operations staff who will run it. Other comments suggested that renewable energy projects create more jobs than facilities such as this one.

Response: The Air District is supportive of creating as many jobs as possible, consistent with environmental protection and other important societal goals, but job creation is not an issue addressed in the Federal PSD Regulations. It was not a part of the Air District's analysis supporting the proposed permit, and it has no impact on the Air District's decision to issue the final permit.

Comment XIX.17. – Consistency With Other Air Quality Regulatory Programs:

The Air District received comments objecting to the issuance of a permit for this facility as inconsistent with other air quality regulatory programs, such as the "smog-check" program for automobiles, the Air District's asbestos regulations, and the District's recently adopted regulations prohibiting wood burning in fireplaces on "Spare the Air" nights.

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[397] *Id.*, pp.105-106 (finding that it is not necessary that there be evidence showing that aging power plants are decommissioned as a consequence of new power plant approval for the CEC to determine that the new plant's environmental impacts would amount to an overall reduction in emissions). The CEC also rejected arguments that the addition of highly efficient natural gas-fired power plants would "crowd out" new renewable energy sources, instead finding that the addition of such highly efficient, dispatchable plants will be needed to successfully integrate renewable generating sources into the grid. *Id.*, pp. 110, 113.

Response: The Air District disagrees that there is any inconsistency in its asbestos, wood-burning, or any other regulations and its permitting of this facility. With respect to wood burning in particular, the San Francisco Bay Area is out of compliance with the National Ambient Air Quality Standards for short-term levels of fine particulate matter ($PM_{2.5}$). The Air District needs to respond to this situation to protect the air that we all breathe. The Air District identified wood burning in fireplaces as a major contributor to unhealthy $PM_{2.5}$ levels on cold, still winter evenings when $PM_{2.5}$ levels are the highest, and so it adopted its wood burning regulations to cut down on unhealthy wood smoke during these periods. This is similar to the approach that EPA's PSD program takes to major facilities such as this one, requiring stringent emission controls as described throughout this document. With these stringent controls in place, this power plant will generate electricity to power the grid burning clean natural gas and with the lowest amount of air pollution achievable using current state-of-the-art technology.

Comment XIX.18. – Effect on Property Values:

The Air District received comments stating that the project will harm property values in Hayward, and suggesting that the Air District should consider impacts on property values in its PSD permit analysis.

Response: The District does not have any information on property values in Hayward. The District is not aware of any PSD permit requirement that is based on property values, and the commenters have not cited any. To the extent that the project will have the potential to negatively impact property values in Hayward, such concerns should be addressed to the City and to the Energy Commission in the context of siting the project at this location. Impacts to property values are not an element of the PSD permit review process.

Comment XIX.19. – Wastewater Storage:

The Air District received comments stating that there appears to be limited wastewater storage available for the project.

Response: The availability of wastewater storage is not an element of the Federal PSD permitting program. The Air District is not aware of any potential problems at the facility with wastewater storage, and the comments did not provide any specific information that there may be a problem with wastewater storage. But to the extent that there are any grounds for such a concern, they should be addressed to the appropriate agency with regulatory jurisdiction over this issue instead of being raised in the Federal PSD permit process.

Comment XIX.20. – Flood Protection:

The Air District received a comment stating that the water level in the San Francisco Bay is rising because of global warming. The comment further stated that the facility is located in a flood plain and will eventually be below the surface level of the Bay, and asked who will be responsible for mitigation measures to keep the facility from being submerged.

Response: To the extent that flood control measures will be required at this facility because of rising water levels, it is not clear at this point what measures could be needed and how they would be paid for should they become necessary. The comment seems to recognize this situation, as it states that criteria for cities and counties to use in assessing these issues are still in the discussion phase. In any event, flood protection issues are not part of the PSD permit review.

Comment XIX.21. – Air District Permitting of Gateway Generating Station:

The Air District received comments alleging that, with respect to a different power plant project known as the Gateway Generating Station, the District has been engaged in a "conspiracy" with PG&E, the project owner, to circumvent PSD requirements for that project. The comments cited written notes prepared by the applicant in that project from a telephone conference between the applicant and Air District staff on August 4, 2008. The applicant's notes state that the conference included a discussion of whether the District should re-notice the proposed amendments to the facility's PSD permit for that project in light of the Environmental Appeals Board's determination in the July 29, 2008, Remand Order in *In re Russell City Energy Co*., PSD Appeal No. 08-01, in which the EAB criticized certain elements of the District's PSD notice procedures. The notes indicate that the District was of the opinion that the draft permit amendments for the Gateway facility should be re-noticed in light of that Remand Order. The applicant's notes also indicate that, according to the applicant's consultant Mr. Gary Rubenstein of Sierra Research, the applicant believed that it could withdraw its application for amendments to its PSD permit that was currently being processed, and wait to submit the application until after the facility started up. The notes indicate that it was Mr. Rubenstein's opinion that if the facility had already started up and was operational, the amendments the applicant was seeking would not be considered a "major" amendment for PSD purposes and would not require PSD review. The notes also indicate, however, that there was a concern expressed that such an approach would amount to an attempt to circumvent the PSD requirements and would not be something that the District could support. The comments cited the applicant's notes in this regard to charge that the District delayed approval of the amended PSD permit to allow the facility to become operational and avoid PSD review, and that as a result the applicant constructed and is operating a facility that does not satisfy applicable PSD regulatory requirements. The comments also noted that the Environmental Protection Agency has issued a Finding and Notice of Violation ("FNOV") for that project stating that the project was constructed and is being operated in violation of applicable PSD regulatory requirements.

Response: The PSD permit status of the Gateway Generating Station is not relevant to the PSD permitting of the Russell City Energy Center. Nothing in these comments suggests that the Russell City Energy Center will not comply with all applicable PSD permitting requirements, or objects that the Air District should not issue a permit for the Russell City facility. These comments are therefore irrelevant here and do not require a response.

Nevertheless, the Air District wishes to respond to these allegations in order to set the record straight with respect to the permitting of the Gateway Generating Station. The Air District strongly denies that it is complicit in any Federal PSD violations by the PG&E, the project owner. To the contrary, it was the Air District that first brought the permitting irregularities regarding Gateway that form the basis of the enforcement action that is now underway to the attention of EPA and PG&E.

When the Air District received the Remand Order from the Environmental Appeals Board, it started reviewing its notice procedures for Federal PSD permits in order to ensure that the

District would comply with the EAB's requirements going forward. This review of the Federal PSD notice procedures was most directly applicable to the Russell City Energy Center, since it was the facility that was the subject of the Remand Order, but it was also applicable to the Gateway facility because the Air District had recently noticed a proposed PSD permit amendment for that facility to increase the facility's CO emissions limit (among other changes). District staff discussed the Federal PSD notice requirements, and the implications of the EAB Remand Order, with PG&E on a number of occasions, including on August 4, 2008. As the consultant's notes indicate, District staff believed that it would be prudent to re-notice the proposed Gateway permit amendment to ensure that it complied with all requirements addressed in the Remand Order. Another subject that District staff discussed with PG&E was whether the amendment would have to be subject to Federal PSD review at all, or whether it could be treated as a minor modification not triggering PSD review. As the notes from the August 4, 2008, meeting indicate, Mr. Rubenstein opined that PG&E could simply withdraw its application and then resubmit it as a minor modification after the facility had completed construction. The Air District objected to this approach however, and indicated that it would not be able to support this approach as it would amount to impermissible circumvention of the applicable PSD requirements. The Air District therefore maintained its position that PSD permit review would be required, and continued working on the permit with the expectation that a further proposed permit amendment would be re-noticed in accordance with the Remand Order and all applicable Federal PSD permit requirements. Before the Air District could re-notice a further proposal, however, PG&E withdrew its permit application. PG&E stated that it had found that it could meet the existing CO limits in its permit, and would not need the increases it had applied for after all.

In addition to reviewing its PSD notice procedures when it received the Remand Order, the Air District also undertook a thorough review of all other aspects of its PSD permitting procedures to determine if there were any other areas in which they may not strictly conform to the requirements of 40 C.F.R. Section 52.21. One area that the Air District identified concerned permit expiration. Section 52.21(r)(2) provides that a Federal PSD permit expires after 18 months if construction has not commenced, whereas Air District regulations provide that a District Authority to Construct does not expire for two years. In light of this discrepancy, the Air District is ensuring that it informs all PSD permit recipients of the 18-month expiration provisions at the time of permit issuance. The Air District also reviewed the permitting history for the Gateway Generating Station in light of this discrepancy, and discovered that it had been renewing the Gateway PSD permit at two-year intervals on the timetable created by Air District regulations, and not every 18 months as required by 40 C.F.R. Section 52.21(r)(2). The Air District subsequently informed EPA Region 9 and PG&E of the situation, and EPA Region 9 determined that the Gateway PSD permit had expired and had not properly been extended. EPA Region 9 determined that the facility had therefore been constructed without a current, valid PSD permit, and commenced the enforcement action referenced in the comments.

This record shows that far from being complicit in allowing violations of federal PSD requirements, the Air District has in fact been careful to ensure that all PSD requirements are fully complied with. After receiving the Remand Order and realizing that it was not appropriate to rely on the language in its PSD Delegation Agreement from Region IX indicating that compliance with Air District regulations would satisfy all PSD requirements as well, the Air

District immediately acted to review its PSD permitting procedures and fix any discrepancies. It informed PG&E that it would have to renotice the proposed Gateway permit amendment to ensure PSD compliance. It disagreed with PG&E's consultant's position that PG&E could withdraw its application for a CO increase and resubmit it after construction was complete to avoid PSD review, and ensured that PSD requirements would be applied to any such amendment (although in the end PG&E determined that it would not need the increased CO limits and did not pursue the amendment further). And it brought the irregularities regarding extensions of the Gateway PSD permit to EPA and PG&E's attention, which allowed EPA to being its enforcement action to cure the alleged PSD violations. Thus, for all of these reasons, the Air District disagrees with the comments suggesting that it is not properly implementing the Federal PSD program requirements and the Delegation Agreement with respect to Russell City, Gateway, or any other facility.

Comment XIX.22. – EPA Enforcement Action Regarding Gateway Generating Station:

The Air District also received comments objecting to the fact that EPA Region 9 is handling claims of PSD non-compliance regarding the Gateway Generating Station through an enforcement action. These comments apparently object to handling claims of PSD violations through an enforcement action because the commenters believe that there is no right to public comment in an EPA enforcement action. These comments are apparently claiming that EPA Region 9 should drop its enforcement action and that the District should undertake a permit proceeding instead as the appropriate means to address claims of PSD violations.

Response: The Air District disagrees with these comments. EPA's enforcement action is the proper mechanism through which to address EPA's claims of violations of the Clean Air Act's PSD requirements. Furthermore, the comments are incorrect that the federal enforcement process does not provide an opportunity for public comment. EPA has provided a public comment opportunity on the Consent Decree that it intends to ask the federal District Court to enter in the case, and members of the public (including some of the commenters on this permit) have in fact submitted comments. The Air District also disagrees that it could do anything in a permit proceeding to address the alleged PSD violations regarding Gateway. The project owner does not currently have a PSD permit application pending with the Air District, and so there is nothing for the District to act on in terms of imposing PSD permit conditions.

Comment XIX.23. – Consistency with AB 32 and Hayward Climate Action Plan:

The Air District received comments stating that the facility is inconsistent with the California Global Warming Solutions Act (AB 32) and the City of Hayward's Climate Action Plan.

Response: Consistency with planning efforts to reduce greenhouse gases generally is not an element of the Federal PSD permitting process. Consistency with AB 32, local climate action plans, and other such plans is something that can be considered in the California Energy Commission's power plant siting process. Questions regarding the consistency with such plans should be raised at the Energy Commission.

Comment XIX.24. – Earthquake Hazard:

The Air District received comments stating that the facility will be located in a seismically active area and will be at risk of suffering from earthquakes.

Response: Earthquake risk is not an element of the Federal PSD permitting process. Concerns about earthquake risk and seismic safety should be addressed in the siting and general environmental review process that is conducted by the California Energy Commission.

Exhibit 6

Poloncarz, Kevin

From: Barry Young [BYoung@baaqmd.gov]
Sent: Thursday, February 04, 2010 12:16 PM
Subject: Russell City Energy Center - Notice of Issuance of Final PSD Permit

Notice of Issuance of Final Prevention of Significant Deterioration (PSD) Permit for the Russell City Energy Center

This notice is to inform you that the Bay Area Air Quality Management District (District) has issued a final federal Prevention of Significant Deterioration (PSD) permit for the Russell City Energy Center, a proposed natural gas-fired combined cycle power plant with a nominal output of 600 megawatts to be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA.

RESPONSES TO PUBLIC COMMENTS

The District received a number of comments on the proposed permit from members of the public. The District appreciates the public's input on this permit, and in response to the comments the District has made a number of changes to strengthen the permit. The District has published responses to all of the public comments it received in a Response to Comments document for this permit. The Response to Comments document is available from the District upon request, and also on the District's website at:
http://www.baaqmd.gov/Divisions/Engineering/Public-Notices-on-Permits/2010/020410-15487/Russell-City-Energy-Center.aspx

ENVIRONMENTAL APPEALS BOARD APPEALS

PSD Permits may be appealed to the Environmental Appeals Board (EAB) pursuant to Section 124.19 of Title 40 of the Code of Federal Regulations. Any person who filed comments on the draft permit or participated in a public hearing about the permit may petition the EAB to review any condition of the permit decision. Any other person may petition the EAB to review any changes that the District has made from the draft permit to the final permit. Any such members of the public must file any appeal no later than March 22, 2010. Appeals must be received by the EAB by this date to be timely. This date provides 45 days from permit issuance to file appeals, which is greater than the minimum 30 days required by law.

Additional information on filing appeals can be found in the EAB's publication A Citizens' Guide to EPA's Environmental Appeals Board, which is available at the EAB's website at www.epa.gov/eab. Additional information can also be obtained from the EAB at the address below, or by telephone at (202) 233-0122.

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

EFFECTIVE DATE OF PERMIT

The permit will become effective March 22, 2010, unless an appeal is filed with the EAB. If an appeal is filed, the effective date of the permit will be suspended until such time as the appeal is resolved.

AVAILABILITY OF DOCUMENTS

The final PSD Permit, the Response to Comments, and all other documents on which the District has based its permitting decision are available for public inspection at District headquarters during normal business hours. In addition, the final permit, the Response to Comments, and other principal documents are available on the District's website at the address above.

FOR QUESTIONS AND ADDITIONAL INFORMATION

Questions on this matter may be directed to Weyman Lee, P.E., Senior Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4796, weyman@baaqmd.gov.

Exhibit 7

From: Alexander Crockett [ACrockett@baaqmd.gov]

Sent: Tuesday, April 06, 2010 3:20 PM

To: Poloncarz, Kevin

Subject: Public Notice for mailing- RCEC-Final Permit Issuance.pdf - Adobe Acrobat Professional

Attachments: Public Notice for mailing- RCEC-Final Permit Issuance.ZIP

Attached is a PDF copy of the notice we sent regarding issuance of the Final PSD Permit for the Russell City Energy Center.

Notice of Issuance of Final Prevention of Significant Deterioration (PSD) Permit for the Russell City Energy Center

This notice is to inform you that the Bay Area Air Quality Management District (District) has issued a final federal Prevention of Significant Deterioration (PSD) permit for the Russell City Energy Center, a proposed natural gas-fired combined cycle power plant with a nominal output of 600 megawatts to be located at 3862 Depot Road, near the Corner of Depot Road and Cabot Boulevard, in Hayward, CA.

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