EXHIBIT F

Pacific Gas and Electric Company
Power Generation
Fossil Plant Construction

Gateway Generating Station
3225 Wilbur Ave.
Antioch, CA 94509
(925) 459-7200

December 18, 2007
GGS-L-00041C

Jack Broadbent
Executive Officer and APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Application for Modifications to Authority to Construct
Gateway Generating Station - Plant No. 18143

Dear Mr. Broadbent:

PG&E is pleased to submit this application for modifications to the authority to construct (ATC) for the Gateway Generating Station in Antioch. The ATC for the project (formerly the Contra Costa Unit 8 Power Project) was originally issued on July 24, 2001, following certification by the California Energy Commission (CEC) on May 30, 2001. Construction of the facility started late in 2001 and was suspended in February 2002, with approximately 7 percent of construction completed. The ATC, which has been renewed three times (in 2003, 2005 and 2007) was transferred to PG&E in January 2007 under the new project name. PG&E restarted construction of the Gateway Generating Station on February 5, 2007, and anticipates that first fire of the first gas turbine will occur on August 29, 2008.

Following its acquisition of the project, PG&E evaluated the facility as originally permitted and determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. The proposed modifications are described in detail in the attached application support document.

Forms P-101B, C, ICE, P, A and HRSA are attached, and supplemental information regarding the proposed project is provided in the enclosed application support document. The filing fee and initial fee payment will be submitted to the District under separate cover. A separate application is being submitted to the CEC, as required under the conditions of the project's CEC license.

If you have any questions regarding the proposed project, please do not hesitate to call me or Nancy Matthews of Sierra Research at (916) 444-6666.

Sincerely,

Thomas Allen

Thomas Allen
Project Manager

attachments

cc: Teresa DeBono, PG&E
Andrea Grenier, Grenier & Associates, Inc.
Scott Galati, Galati & Blek
Nancy Matthews, Sierra Research
Regional Administrator, USEPA Region 9

sierra research

Application to the Bay Area Air Quality Management District for Modifications to the Authority to Construct for the Gateway Generating Station Antioch, CA

prepared for:

Pacific Gas & Electric Company

December 2007

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95814
(916) 444-6666

APPLICATION TO THE
BAY AREA AIR QUALITY MANAGEMENT DISTRICT
FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT
FOR THE GATEWAY GENERATING STATION
ANTIOCH, CALIFORNIA

Prepared for:

Pacific Gas & Electric Company

December 2007

Prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, CA 95811
(916) 444-6666

SUMMARY

Pacific Gas & Electric Company (PG&E) completed the acquisition of Contra Costa Unit 8 (CC8) from Mirant Delta, LLC in late 2006 and subsequently received approval from the California Energy Commission to change the name of the project to the Gateway Generating Station. The Bay Area Air Quality Management District (District) has transferred the Authorities to Construct (ATCs) for the Gateway Generating Station project to PG&E. PG&E has evaluated the facility as originally permitted and has determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. With this application, PG&E is proposing to make the following changes to the permitted facility:

- Eliminate the 10-cell wet cooling tower and replace it with a dry cooling system, including an exempt wet surface air cooler;
- Replace the permitted natural gas-fired preheater with a smaller dewpoint heater and increase allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup operations;
- Reduce the permitted hourly emission rates for NOx, CO and PM_{10}, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Increase the daily and annual emission rates for CO, based on operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 hp Diesel fire pump at the facility.

These changes will require the following types of changes to the permit conditions:

- Eliminate conditions related to the wet cooling tower;
- Revise conditions related to the natural gas-fired preheater;
- Revise conditions related to emission limits during startup;
- Reduce allowable hourly NOx, CO and PM_{10} emission limits for the Gas Turbines and Heat Recovery Steam Generators (HRSGs);
- Increase allowable daily and annual CO emission limits for the Gas Turbines and HRSGs;
- Revise the commissioning limits; and
- Revise the requirements related to emissions offsets.

This application support document discusses the proposed modifications, presents revised emissions calculations and ambient air quality modeling results, demonstrates the project's continued compliance with all applicable rules and regulations, and provides proposed revisions to the permit conditions. The only annual emissions increase proposed in this application is for

CO. Since the proposed annual increase in CO emissions is above the PSD significance threshold, the proposed modification is subject to PSD review for CO.

APPLICATION TO THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT FOR GATEWAY GENERATING STATION ANTIOCH, CALIFORNIA

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

PART I. PROJECT DESCRIPTION

A. Applicant's Name and Business Description

Name: Pacific Gas & Electric Company

Address: 3225 Wilbur Avenue
Antioch, CA 94509

Contact: Tom Allen, Project Manager
(925) 459-7200

Mailing Address for Permits:

Same as above, with copy to:

Sierra Research
1801 J Street
Sacramento, CA 95811

General Business Description: Electric generation

Responsible Official:

John S. Keenan, Senior VP Generation and CNO
Pacific Gas & Electric Company

Air Quality Consultants:

Sierra Research
1801 J Street
Sacramento, CA 95811
Contact: Nancy Matthews
(916) 444-6666

Type of Use Entitlement: PG&E will own and operate the project.

Estimated Construction Date: Construction of the permitted units is underway, in accordance with the existing Authority to Construct. Construction of the exempt units (including the air-cooled condenser in place of the cooling tower) is also underway. Construction of the proposed modifications to permit units, the dewpoint heater and fire pump engine, is expected to begin upon issuance of the revised Authority to Construct.

B. Type of Application

This is an application for modification to existing Authorities to Construct.

C. Description of the Proposed Project

The Gateway Generating Station Project (formerly Contra Costa Unit 8, or CC8) was permitted to consist of the following equipment:

- S-41 and S-43: Two Combustion Gas Turbines, General Electric Frame 7FA Model PG 7231 or equivalent; equipped with dry low-NOx combustors, abated by selective catalytic reduction systems and oxidation catalysts;
- S-42 and S-44: Two Heat Recovery Steam Generators (HRSGs), equipped with low-NOx duct burners, abated by selective catalytic reduction systems and oxidation catalysts;
- S-46: One 10-cell wet cooling tower;
- S-45: One natural gas-fired preheater; and
- S-48: One oil-water separator.

PG&E proposes to make several changes to the Gateway Generating Station Project (GGS) permit, as follows:

- Eliminate S-46, the 10-cell wet cooling tower, and replace it with an air-cooled condenser and a wet surface-air cooler, both of which are exempt from District permitting requirements;
- Replace the permitted natural gas-fired preheater, S-45, with a smaller unit and increase its allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup and shutdown operations;
- Reduce the permitted hourly mass emission and concentration limits for NOx, CO and PM_{10}, based on current BACT and operating experience;
- Change the ammonia slip limit;
- Reduce the permitted PM_{10} emissions for the project;
- Increase the permitted daily and annual CO emissions for the project to reflect the revised CO startup emission rates;
- Revise the allowable CO and POC emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 kW Diesel fire pump engine.

As a result of these proposed changes, PG&E is requesting permit condition changes that will reflect the revised emission rates and operating conditions for the permitted units. The overall increases in allowable CO emissions from the facility will trigger PSD review for that pollutant. Because the cooling tower is being eliminated, annual PM_{10} emissions, and therefore the facility's PM_{10} offset obligations, will be reduced.

D. Project Emissions

This section of the application presents an assessment of the emissions from the revised PG&E project design. These revisions include reducing the NOx and CO emissions from the gas turbines and HRSGs to reflect current BACT; reducing the PM_{10} emission limit for the units during duct firing; changing the ammonia slip limit; eliminating the wet cooling tower and associated PM_{10} emissions; and adding a new Diesel-fueled fire pump engine. The analysis of the new project design also includes reductions in NOx and increases in CO from the gas turbines during startup.

1. Emissions from the Gas Turbines and HRSGs

The gas turbine and duct burner emission rates have been estimated from vendor data, current BACT limits, new maximum fuel consumption rates, and established emission calculation procedures. The changes in emissions are a result of: (1) the proposed reductions in NOx, CO and PM_{10} concentrations and mass emission limits during normal operations; and (2) revised emission rates and operating assumptions for the turbines during startup. The maximum emission rates for the combustion turbines alone and for the combustion turbines with duct burners are shown in Tables 1 and 2, respectively. The emission data and operating parameters that are the basis for these emission rates are shown in Appendix A, Table A-1. Proposed new emission limits during turbine startup are shown in Table 3.

Table 1
Maximum Pollutant Emission Rates
Each Gas Turbine[1]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr[2]
NOx	2.0[3] (2.5)	0.0072 (0.009)	13.40
SO_2[4]	0.57	0.0028	5.22
CO	4.0[3] (6.0)	0.0088 (0.0132)	16.31
POC	2.0[3]	0.0017	4.67
PM_{10}[5]	--	--	11.0
NH_3	10 (5)	--	24.80

Notes:
1. Emission rates shown reflect the highest value at any operating load, without duct firing. Numbers in parentheses show current limit where changes are proposed.
2. Current ATC does not include lb/hr limits for the CTGs without duct firing.
3. Current BACT.
4. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
5. 100% of particulate matter emissions assumed to be emitted as PM_{10}/$PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.

Table 2 Maximum Pollutant Emission Rates Each Turbine with Duct Burners[1]			
Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr
NOx	2.0[2] (2.5)	0.0072 (0.009)	15.18 (20)
SO_2[3]	0.57	0.0028	5.92 (6.18)
CO	4.0[2] (6.0)	0.0088 (0.0132)	18.49 (29.22)
POC	2.0[2]	0.0017	5.29 (5.6)
PM_{10}[4]	--	--	12(13)
NH_3	10 (5)	--	28.10

Notes:
1. BAAQMD permit limit. Numbers in parentheses show current limit where changes are proposed.
2. Current BACT.
3. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
4. 100% of particulate matter emissions assumed to be emitted as $PM_{10}/PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.

Table 3 Maximum Emission Rates During Turbine Startup (Each Turbine)[1]			
	NOx	CO	POC
Cold Start, lb/hour	160 (n/a)	900 (n/a)	16 (n/a)
Cold Start, lb/start[2]	600 (452)	5,400 (990)	96 (109)
Hot Start, lb/start[3]	160 (189)	900 (291)	16 (26)

Notes:
1. Estimated based on operating experience for other 7FA CTGs in combined cycle. See Appendix A, Table A-1. Numbers in parentheses show current limit where changes are proposed.
2. Maximum of six hours per cold start.
3. Maximum of one hour per hot start.

The current permit conditions include separate emissions limits for cold startup, hot startup and shutdown. PG&E proposes to eliminate these separate limits and replace them with a single set of limits expressed in units of pounds per hour and pounds per startup. The proposed pounds per startup limit assumes a maximum of six hours for a full cold start.

Components of the gas turbine combustor assemblies must be replaced periodically because these components have a limited operational life. After the new gas turbine combustor components are installed, each gas turbine's fuel system must be tuned to meet the manufacturer's specifications for emissions and acoustic dynamics. During this tuning process the turbines must operate at low loads intermittently for up to six hours with potentially elevated emission rates. Combustor tuning activities would also be covered by the proposed startup emission limits.

NOx Emissions Excursions

In the experience of many operators of gas turbines that are controlled to extremely low NOx levels using dry low-NOx combustors, there are some short-term turbine operating conditions that may cause temporarily elevated NOx levels. During these brief periods, the turbine-out NOx emissions are elevated to levels that exceed the SCR system's ability to maintain compliance with the 2 ppmc NOx limit on a one-hour average basis. PG&E requests that the District include in the revised permit a condition that allows a limited number of excursions above the 2 ppmc limit so that these conditions that are beyond the operator's control will not be considered violations of the permitted emissions limit. This excursion language has been included in many permits issued for gas turbines since 2001, when NOx limits became extremely stringent and averaging periods were reduced to one hour. The proposed condition language is as follows:

> *Compliance with the hourly NOx emission limits specified in Condition 20a shall not be required during short-term excursions of less than 10 hours per rolling 12-month period.*
>
> *Short-term excursions are defined as 15-minute periods designated by the applicant, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2 ppmvd corrected to 15% O_2. Maximum 1-hour average NOx concentrations for periods that include short-term excursions shall not exceed 30 ppmvd corrected to 15% O_2. All emissions during short-term excursions shall be included in all calculations of daily and annual mass emissions required by this permit.*

Ammonia Slip Limit

PG&E is also proposing to change the ammonia slip limit from 5 ppmvd @ 15% O_2 (ppmc), as specified in Condition 20e, to 10 ppmc. This request is made in conjunction with reducing the NOx limit from 2.5 ppmc to 2.0 ppmc on a 1-hour average basis. Although the previous owner of the project had agreed to meet a 5 ppmc ammonia slip limit, that limit was combined with a 2.5 ppmc NOx limit. Because of the additional demands on the NOx control system to achieve a 2.0 ppmc NOx limit, it would be extremely difficult to maintain continuous compliance with a 5 ppmc ammonia slip limit. The screening health risk assessment provided in Section II.B demonstrates that there are no significant public health impacts associated with the 10 ppmc ammonia slip level.

Moreover, we do not believe there is an air quality basis for requiring a lower ammonia slip level for the project. In a previous FDOC for a project in the Bay Area, the BAAQMD staff stated:[1]

> *…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.*

The assessment of ammonia emissions and the screening health risk assessment in the CC8 FDOC were based on an ammonia slip limit of 10 ppmvd, so the proposed change will not affect the analyses presented there. However, by agreement of the original applicant, the limit was changed in the final permit conditions from 10 ppmvd to 5 ppmvd.

2. Emissions from the Turbine Cooling System

PG&E has eliminated wet cooling from the project design and is using an air-cooled condenser (ACC) system instead. Components of the wet cooling system that will no longer be required and have therefore been eliminated from the original project design include the water supply pipeline, wet cooling tower, surface condenser, associated convenience systems, and the cooling tower chemical treatment system. New components to support the ACC system include a condensate polishing system, a new water supply source, and a wastewater discharge source. There are no air emissions associated with the ACC system.

The project as permitted incorporated evaporative cooling on the combustion turbine air inlets. However, due to the change in the project's water supply, PG&E proposes to eliminate this option and replace the evaporative cooling system with an electric chiller system. There are no air emissions associated with the electric chiller system.

In addition to the changes in the cooling water system, PG&E has also reviewed the water demand of the combustion turbine's steam power augmentation (PAG) systems. As a result of this review, PG&E has determined that the water demand and economic implications do not warrant implementing PAG on the combustion turbines.

Finally, PG&E has determined that a small fin-fan heat exchanger in combination with a wet surface air cooled (WSAC) heat exchanger system will be used to provide the necessary heat rejection capacity for auxiliary plant systems. The proposed fin-fan system is similar to the ACC system. The WSAC system is a hybrid between a wet cooling tower and fin-fan heat exchanger, and uses water sprayed over the heat transfer bundles to increase the cooling capacity of the system.

---

[1] Final Determination of Compliance, East Altamont Energy Center LLC, July 10, 2002, p. 12.

Based on the conservatively high operating assumptions shown in Appendix A, Table A-2, emissions from the WSAC will be less than 1 lb/hr and 1 tpy. In the WSAC process, the warm process water is cooled in a closed-loop tube bundle so the process water being cooled never comes in contact with the outside air. Therefore, the WSAC is exempt from permitting under BAAQMD Rule 2, Section 2-1-128.4 ("Water cooling towers and water cooling ponds not used for evaporative cooling of process water, or not used for evaporative cooling of water from barometric jets or from barometric condensers").[2]

3. Emissions from the Dewpoint Heater

The current version of the ATC includes a natural gas-fired fuel gas preheater (dewpoint heater) rated at 12 MMBtu/hr. The ATC includes a condition limiting daily heat input to the fuel gas preheater to 192 MMBtu/day, effectively restricting the heater to 16 hours per day of operation. PG&E anticipates the need to operate the dewpoint heater up to 24 hours a day under some ambient conditions, so is proposing to substitute a smaller unit rated at approximately 6.5 MMBtu/hr (HHV). Specifications for the dewpoint heater are shown in Appendix A, Table A-3. Emissions from the replacement heater are shown in Table 4.

Table 4
Maximum Pollutant Emission Rates
Natural Gas-Fired Dewpoint Heater

Pollutant	ppmvd @ 3% O_2[1]	lb/MMBtu (HHV)[1]	lb/hr[2]	lb/day[3]
NOx	50	0.060	0.39	9.4
SO_2[4]	--	0.0028[4]	0.018	0.4
CO	40	0.029	0.19	4.6
POC	5.5	0.0045	0.029	0.7
PM_{10}	--	0.0074	0.048	1.2

Notes:
1. Performance from manufacturer at rated load.
2. Manufacturer's not-to-exceed emission rate.
3. Based on 24 hours per day of operation.
4. SO_2 emissions in lb/MMscf, based on natural gas sulfur content of 1 gr/100 scf.

[2] Rule 2, Section 2-1-128 exempts sources listed in the subsection, "provided that the source does not require permitting pursuant to Section 2-1-319." Section 2-1-319 requires permitting of sources with emissions in excess of 5 tpy.

4. Emissions from the Diesel Fire Pump Engine

PG&E is also proposing to install a 300 bhp emergency Diesel driven fire pump engine at GGS. The fire pump engine will be Tier 2-certified and will meet the requirements of the ARB Air Toxics Control Measure. Operation of the fire pump engine for testing and maintenance will be limited to one hour per day and 50 hours per year. Hourly and annual emissions from the Diesel fire pump engine are summarized in Table 5. Specifications for the fire pump engine are provided in Attachment A, Table A-4.

Table 5
Maximum Pollutant Emission Rates
Emergency Diesel Fire Pump Engine

Pollutant	g/bhp-hr[1]	lb/hr	tons/yr[2]
NOx	4.36	2.88	0.1
SO_2[3]	--	0.0029	<0.01
CO	0.32	0.21	<0.1
POC	0.29	0.19	<0.1
PM_{10}[4]	0.12	0.08	<0.1

Notes:
1. Based on manufacturer's specifications for Clarke Model JU6H-UF40 Tier 2 fire pump engine.
2. Based on 50 hours per year of operation for testing and maintenance, per the ATCM.
3. Based on the use of ultra-low sulfur CARB Diesel fuel with maximum sulfur content of 15 ppm.

5. Fuel Use Limits for Permitted Equipment

The maximum heat input rates (fuel consumption rates) for the gas turbines and duct burners are shown in Table 6.

Table 6 **Hourly, Daily, and Annual Fuel Use**[1]			
Units	Dewpoint Heater	Gas Turbines plus Duct Burners, each[2]	Total Fuel Use, all units[3]
MMBtu/hr	6.5 (12)	2094.4 (2227)	4,195.3
MMBtu/day	156 (192)[4]	50,265.6 (49,950)	100,687.2
MMBtu/yr	56,940	34,900,000[5]	34,956,940

Notes:
1. Numbers in parentheses show current permit limit where changes are proposed. MMBtu are HHV.
2. Based on maximum heat input for full load turbine operation at 23° F plus duct burner for maximum daily operation; based on full load turbine operation at 60° F plus duct burner, maximum of 22.5 hours per day and 5100 hours per year per duct burner for annual operation.
3. Includes S-41, S-42, S-43, S-44 and S-45.
4. Daily limit from ATC Condition 47.
5. Annual limit for both CTG trains, from ATC Condition 16.

6. Total Emissions for the Facility

The maximum annual, daily, and hourly emissions proposed for GGS are shown in Table 7. Detailed emissions calculations from the individual permit units are shown in Appendix A, Table A-5. Although the calculations of daily and annual emissions of NOx, SO_2 and POC show that emissions from the facility after the proposed permit changes are expected to be lower than the levels originally permitted for CC8, PG&E is not proposing to change the annual emission limits for these pollutants.

Table 7 **Emissions from Facility Equipment**					
	NOx	SO_2	CO	POC	PM_{10}
Maximum Hourly Emissions, lb/hr					
Turbines and Duct Burners[1]	175.2	11.8	918.5	21.3	22.0
Dewpoint Heater	0.4	<0.1	0.2	<0.1	<0.1
Fire Pump Engine[2]	2.9	<0.1	0.2	0.2	0.1
Total Project, pounds per hour[3]	178.5	11.9	918.9	21.5	24.3
Original Analysis[4]	170	12.4	541	109	26
Maximum Daily Emissions, lb/day					
Turbines and Duct Burners[1]	1,746.6	284.0	11,465.6	382.6	576.0
Dewpoint Heater	9.4	<0.1	4.6	0.7	1.2
Fire Pump Engine[2]	2.9	<0.1	0.2	0.2	0.1

Table 7 **Emissions from Facility Equipment**					
	NOx	SO_2	CO	POC	PM_{10}
Total Project, pounds per day[3]	1,759.0	284.0	11,470.3	384.4	577.2
Current Permit Limits[5]	1,994	297	3,602	468	624
Permit Limits After Modification, lb/day	**1,994**	**297**	**11,470.3**	**468**	**577.2**
Maximum Annual Emissions, tpy					
Turbines and Duct Burners[1]	149.6	37.0	554.3	45.3	101.5
Dewpoint Heater	1.7	0.1	0.8	0.1	0.3
Fire Pump Engine	0.1	<0.1	<0.1	<0.1	<0.1
Total Project, tons per year[3]	151.4	37.0	555.1	45.4	101.7
Current Permit Limits[5]	174.3	48.5	259.1	46.6	112.2[6]
Permit Limits After Modification, tpy	**174.3**	**37.0**	**555.1**	**46.6**	**101.7**

Notes:

1. Includes startup emissions.
2. Calculations reflect one hour per day and 50 hours per year of operation for the fire pump for testing and maintenance.
3. Numbers may not add directly due to rounding.
4. Appendix B of the FDOC, turbines and duct burners only. NOx, POC and CO emissions shown are emission rates during startup. SO_2 and PM_{10} emissions reflect duct firing.
5. Current daily permit limit applies to gas turbines and HRSGs only; annual permit limit applies to all permitted units.
6. Current PM_{10} limit includes wet cooling tower, which is being eliminated in this amendment.

7. Noncriteria Pollutant Emissions

The noncriteria pollutants that may be emitted from the gas turbines and HRSGs at GGS, and their respective emission factors, are shown in Table 8. Noncriteria pollutant emissions from the dewpoint heater, which total 6.3 lb/yr, are shown in detail in Table A-7, Appendix A. Diesel particulate matter (DPM) emissions from the Diesel fire pump engine will not exceed 4.0 lb/yr, based on 50 hours per year of operation for testing and maintenance.

Pollutant	Emission Factor (lb/MMscf)	Emissions	
		lb/hr, each	ton/yr, total (two trains)
Acetaldehyde	4.08×10^{-2}	0.084	0.7
Acrolein	3.69×10^{-3}	0.0076	6.4×10^{-2}
Ammonia[2]	--[3]	28.1	238.9
Benzene	3.33×10^{-3}	0.0069	5.7×10^{-2}
1,3-Butadiene	4.39×10^{-4}	0.0009	7.6×10^{-3}
Ethylbenzene	3.26×10^{-2}	0.068	0.6
Formaldehyde	3.67×10^{-1}	0.76	6.3
Hexane	2.59×10^{-1}	0.54	4.5
Naphthalene	1.66×10^{-3}	0.0034	2.8×10^{-2}
Other PAHs[4]	1.79×10^{-4}	0.0004	3.1×10^{-3}
Propylene[2]	7.71×10^{-1}	1.60	13.3
Propylene Oxide	2.98×10^{-2}	0.006	0.5
Toluene	1.33×10^{-1}	0.28	2.3
Xylene	6.53×10^{-2}	0.14	1.1
Total HAPs			**16.2**

Table 8
Noncriteria Pollutant Emissions for the Gas Turbines with Duct Firing[1]

Notes:
1. See Appendix A, Table A-8 for source of emission factors and basis of calculations.
2. Ammonia and propylene are not HAPs.
3. Ammonia emissions calculated from 10 ppm ammonia slip rate.
4. Includes benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, and indeno(1,2,3-cd)pyrene

8. Commissioning Emissions

Based on a review of commissioning experiences at other large turbine projects, PG&E is proposing changes in some of the emission limits for the commissioning period in the ATC. The current permit limits and the proposed new limits are shown in Table 9 below.

Table 9
Emission Limits for the Commissioning Period

	Current Limits		Proposed Limits	
Pollutant	lb/day	lb/hr	lb/day	lb/hr
NOx	8,400	400	no change	no change
CO	13,000	584	40,000	4,000
POC	535	--[1]	1,600	--
PM_{10}	624	--	432	--
SO_2	297	--	no change	--

Note:

1. No limit in current permit.

PART II. DEMONSTRATION OF REGULATORY COMPLIANCE

This section summarizes the applicable BAAQMD rules and regulations and describes how the proposed modification will comply with these requirements.

A. Regulation 2, Rule 2: New Source Review

The new source review requirements that are applicable to the proposed modification are:

- Best Available Control Technology (BACT) requirements (Rule 2-2-301);
- Offset requirements (Rules 2-2-302 and 2-2-303); and
- Ambient air quality impact analysis (Rule 2-2-305.2).

PSD air quality analysis requirements (Rule 2-2-305.2) are applicable because the CO emissions increases resulting from the proposed modifications will be above the PSD *de minimis* level (see Section III).

1. Best Available Control Technology

Rule 2-2-301 requires the application of BACT to an emissions unit with emissions in excess of 10 pounds per day. Table 10 compares the emissions from the gas turbines/HRSGs to the 10 lb/day threshold and shows the corresponding BACT determinations.

Table 10
Applicability of BACT to the Gas Turbines/HRSGs

Pollutant	Emissions per Train, lb/day	BACT
NOx	873.3	SCR (2.0 ppmc, 1-hour avg)
SO_2	142.0	natural gas fuel
CO	5,732.8	oxidation catalyst (4.0 ppmc, 3-hour avg)
POC	191.3	oxidation catalyst (2.0 ppmc, 3-hour avg)
PM_{10}	288.0	natural gas fuel

The District made BACT determinations for the facility when the Authority to Construct was issued in 2001, and PG&E has reviewed the current BACT requirements that would be applicable were the facility to be permitted now. While the control technology proposed for the original permit still constitutes BACT, the NOx and the CO emission concentration levels considered to be BACT have been reduced. GGS is proposing to reduce the permitted hourly

NOx and CO emission concentrations and mass emission rates during normal operation to reflect current BACT.

As shown in Tables 4 and 5, emissions from the natural gas-fired dewpoint heater and the Diesel fire pump engine will be less than 10 lb/day, so these units are not subject to BACT requirements.

2. Offset Requirements

Rule 2-2-302 requires POC and NOx emission reduction credits to be provided for facilities that will emit 10 tons per year or more. If the facility will emit 35 tons per year or more on a pollutant-specific basis, the offsets must be provided at a ratio of 1.15:1.0. Offsets must be provided at a ratio of 1.0:1.0 if emissions are between 10 and 35 tons per year.

Rule 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tons per year of SO_2 and PM_{10}. If required, these offsets must be provided at a ratio of 1.0:1.0.

Table 11 below summarizes the offset requirements for the proposed modification. The table shows the facility emissions after the modifications, the offset requirements under Rules 2-2-302 and 2-2-303, the offsets provided for the original application, and the remaining offsets required.

Table 11
Summary of Offset Requirements

Pollutant	Total Facility Emissions (tpy)	Offset Ratio	Total Offsets Required (tpy)	Offsets Provided for CC8	Offsets to be Refunded (tpy)
NOx	174.3	1.15:1.0	200.5	200.5[1]	0
POC	46.6	1.15:1.0	53.6	53.6[1]	0
PM_{10}	101.7	1.0:1.0	101.7	112.2[2]	10.5

Notes:
1. NOx and POC ERCs from Banking Certificate #693 (Gaylord Container, Antioch).
2. PM_{10} offsets were provided in the form of SO_2 ERCs at a ratio of 3:1. The SO_2 ERCs were from Banking Certificates #693 (Gaylord Container, Antioch), #694 (PG&E, Martinez) and #695 (Hudson ICS, San Leandro).

3. Ambient Air Quality Modeling Requirements

Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.2 and 2-2-305.2), a major modification to a major facility must perform modeling to assess the net air quality impact of that pollutant, if the cumulative increase minus the contemporaneous emission reduction credits at the facility exceed maximum annual pollutant emissions in excess of the trigger levels shown in Table 12. Under Regulation 2-2-605.4, the baseline emission rate used to determine the contemporaneous emission reduction credits is equal to the emission cap that has been fully offset by the facility.

Table 12
Comparison of GGS Cumulative Emissions Increase with PSD Trigger Levels

	Emissions, tons per year			
Pollutant	GGS Proposed Emissions	CC8 Emissions, as permitted and fully offset[1]	Net Increase (Decrease)	PSD Trigger
NOx	174.3	174.3	--	40
SO_2	37.0	0[2]	37.0	40
CO	555.1	0[2]	555.1	100
POC	46.6	46.6	--	40
PM_{10}	101.7	112.2	(10.5)	15

Notes:
1. From Table C-1 of the FDOC.
2. No offsets were required or provided for SO_2 and CO emissions from CC8.

Since the cumulative increases in CO emissions exceed the PSD trigger level of 100 tpy, an ambient air quality impact analysis must be performed for CO. The required ambient air quality impacts analysis is provided in Part III of this application.[3]

B. Screening Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed project. In accordance with the requirements of the Reg. 2, Rule 5 (Toxics New Source Review) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

The screening health risk assessment prepared for the CC8 project showed that the carcinogenic and chronic risks from the project as approved would be below significant impact thresholds. While PG&E proposes to increase allowable annual ammonia emissions from the CTGs and HRSGs by increasing the allowable ammonia slip from 5 ppm to 10 ppm, the original screening health risk assessment was based on 10 ppm ammonia slip so the proposed change will not affect

[3] Because this amendment includes increases in short-term NOx emissions during commissioning, the ambient air quality impact analysis also includes an evaluation of short-term NO_2 impacts from the project.

that conclusion. In fact, by eliminating the wet cooling tower, the potential health risk from the project would be reduced. However, since the proposed modifications to the approved facility include the addition of a Diesel fire pump engine and Diesel particulate matter (DPM) is considered a toxic air contaminant, a new screening health risk assessment has been prepared that includes the Diesel fire pump engine. The results of the revised screening health risk assessment are presented in Table 13. A detailed discussion of the screening health risk assessment procedures and assumptions is provided in Appendix C to this application.

Table 13
Screening Health Risk Assessment Results

Source	Carcinogenic Risk (in one million)	Chronic Health Hazard Index	Acute Health Hazard Index
Gas Turbines and HRSGs, Dewpoint Heater	0.16	0.01	0.09
Diesel Fire Pump Engine	0.96	<0.01	n/a
Total, All Sources	1.04	0.01	0.09

The maximum cancer risk from the facility, which is due mainly to the Diesel particulate matter emissions from the fire pump engine, is slightly higher than 1 in one million. Since the fire pump engine PM emissions comply with the 0.1 g/bhp-hr level considered toxics BACT (T-BACT), the risk is considered acceptable. In addition, the area where the cancer risk is predicted to exceed 1 in one million is limited to receptors at the southeast fenceline of the plant property.

C. Other District Rules and Regulations

In the Final Determination of Compliance issued for CC8 in February 2001, the District staff determined that the facility would comply with all other applicable District rules and regulations. The proposed modifications in this application do not change the District's conclusions regarding the applicable rules and regulations or the compliance of the gas turbines, HRSGs and dewpoint heater. The compliance of the facility, including the proposed Diesel fire pump engine, is summarized in this section.

1. <u>Regulation 1, Section 301: Public Nuisance</u>

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.

2. 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, PG&E has submitted an application to the District to obtain a modified Authority to Construct and Permit to Operate for the proposed S-41 & S- 43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater, S-48 Oil Water Separator and S-50 Diesel Fire Pump Engine.

3. Regulation 2, Rule 3: Power Plants

Because the GGS has already received its license from the California Energy Commission, the District's review does not fall under the requirements of Regulation 2, Rule 3.

4. Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, PG&E has submitted a Major Facility Review application for the facility as originally permitted. An amended MFR permit application will be submitted to reflect the modifications proposed in this application.

5. Regulation 2, Rule 7: Acid Rain

The GGS 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), GGS must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. The required Acid Rain Permit Application was submitted to the District and to EPA in December 2006.

6. Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NOx burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners 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. In the DOC for the original project, the District staff determined that the grain loading resulting from the simultaneous operation of each power train would comply with the grain loading limit. Since PG&E is proposing to reduce the PM_{10} emissions from the gas turbines and HRSGs during duct firing, the compliance margin will be even greater.

7. Regulation 7: Odorous Substances

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

8. Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively in the GGS gas turbines and duct burners.

9. Regulation 9: Inorganic Gaseous Pollutants

- Regulation 9, Rule 1, Sulfur Dioxide
- Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations
- Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters
- Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

The DOC for the original project made the determination that the project was in compliance with or exempt from these rules. No changes to the project are being proposed that would affect these determinations.

D. Other Federal Requirements

1. New Source Performance Standards

The federal new source performance standards (NSPS) establish standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards [NAAQS]) from new or modified facilities in specific source categories. The NSPS for Stationary Gas Turbines and for Stationary Compression Ignition Internal Combustion Engines will be applicable to the proposed project.

When the project was originally permitted, the gas turbines were subject to the requirements of Subpart GG. However, since the facility did not commence construction as defined under the NSPS before February 18, 2005, the requirements of Subpart KKKK are now applicable.[4]

[4] The previous owner of the project, Mirant, commenced construction under a valid ATC in 2001, but suspended construction in 2002. Because substantial use had been made of the ATC, the BAAQMD renewed the ATC in accordance with Rule 2-1-407.3. However, the NSPS defines "commence" as "undertak[ing] a continuous program of construction…or…entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction…" (40 CFR 60.2) A suspension in construction of longer than 18 months is generally used by EPA to determine that construction has not been continuous.

Subpart KKKK limits NOx and SO2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 30 MW are 0.39 lb NOx per MW-hr and 0.58 lb SO2 per MW-hr. The emission limits of 2.0 ppmc NOx and 0.56 ppmc SO2 proposed for GGS are well below the Subpart KKKK limits, as shown in Table 14.

Table 14
Compliance With 40 CFR 60 Subpart KKKK

Pollutant	Proposed Permit Limits			Subpart KKKK Limit, lb/MW-hr
	ppmc	lb/hr	lb/MW-hr (max)	
NOx	2.0	15.2	0.08	0.39
SO_2	0.56	5.9	0.03	0.59

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the GGS gas turbines will be equipped with continuous NOx emissions monitors, ongoing annual performance testing will not be required under the NSPS.

For the size of engine proposed for the emergency fire pump engine, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, requires facilities to purchase engines meeting the EPA engine non-road certification level of Tier II or better depending on the year the engine is manufactured/purchased. This regulation also requires the engines to use ultra-low sulfur content Diesel fuel.

2. National Emissions Standards for Hazardous Air Pollutants

The calculations in Section 1.D. of this application demonstrate that emissions of HAPs from the facility will be well below the major source thresholds of 10 tons per year of individual HAP or 25 tons per year of total HAPs. Therefore, the facility is not subject to the MACT requirements of the National Emissions Standards for Hazardous Air Pollutants.

Part III. PSD Ambient Air Quality Impact Analysis

As shown in Table 14 above, the cumulative increases in emissions from the proposed changes are below the PSD significant emissions thresholds for all pollutants except CO. Since the net increase in emissions of this pollutant exceeds the applicable significance threshold, a revised ambient air quality analysis is required for CO. Because changes are being proposed to the emission rates during gas turbine startup and commissioning, new startup modeling has also been carried out.

A. Air Quality Modeling Methodology

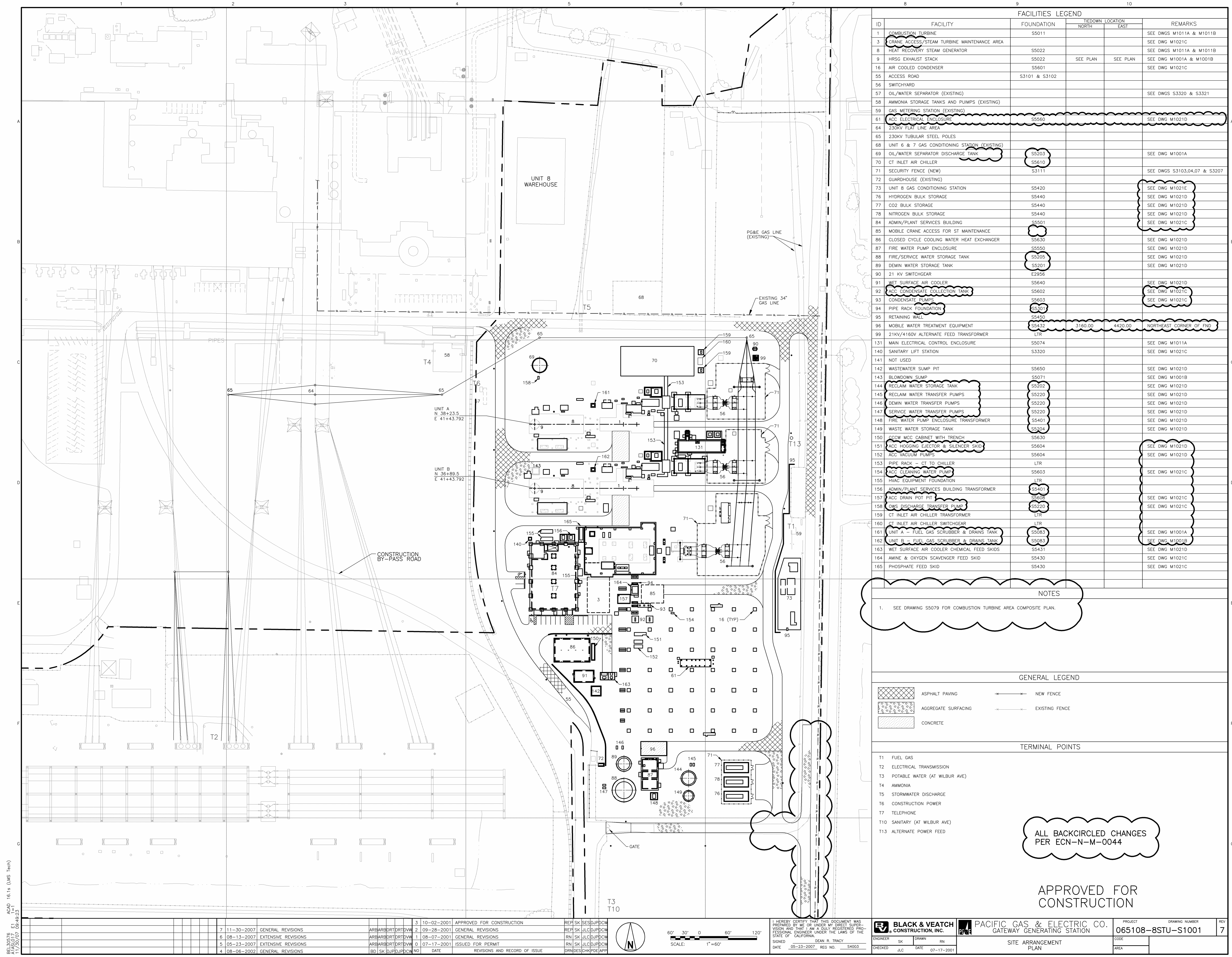
The assessment of impacts from GGS on ambient air quality has been conducted using the EPA guideline models SCREEN3 and AERMOD and three years of surface meteorological data (2004 through 2006) collected by Mirant at the Contra Costa power plant less than ½ mile from the project site.[5] Upper air data were obtained from Buchanan Field in Concord.[6] The ambient air quality impact analysis was conducted in accordance with the protocol filed with the District in August 2007 and the comments provided by the District staff in October 2007 (see Appendix B, Attachment B-1).The surface parameters developed for use in the AERMET meteorological data input are documented in Appendix B, Attachment B-2. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Impacts were evaluated in simple and complex terrain and under inversion breakup and shoreline fumigation conditions. The PV Molar Ratio Method was used to convert one-hour NOx impacts into one-hour NO_2 impacts. Figure 1 shows the layout of the facility and the location of each exhaust stack. Building dimensions used in the BPIP analysis are summarized in Table B-1 of Appendix B, and are shown in detail in the modeling files provided.

Emissions from the turbines will be exhausted from two 195-foot exhaust stacks. The project also includes emissions from the dewpoint heater with a release height of approximately 15 feet,

[5] The original AQIA for CC8 was carried out using ISCST3. Since that time, EPA has adopted AERMOD as a guideline model to replace ISCST3.

[6] Although BAAQMD policy to limit mixing height to 600 meters, it is not possible to impose this limit in the AERMOD modeling system.

Figure 1
Facility Layout



the wet surface air cooler with a release height of approximately 19 feet, and the small Diesel fire pump engine with a release height of 10 feet 8 inches.[7]

B. Air Quality Impact Analysis

1. Screening Analysis for Turbines/HRSGs

The original permit application had identified 11 different likely operating conditions for the turbines and HRSGs that reflect a range of operating temperatures and loads, with and without the duct burners in operation. With the elimination of PAG and modifications to the duct firing capability of the units, the 11 operating conditions have been reduced to eight conditions, which are summarized below in Table 15. Emission rates and stack parameters for these operating conditions are shown in Appendix B, Table B-2.

Table 15
Turbine Operating Conditions for Screening Analysis

Condition Number	Turbine Load	Ambient Temp, deg. F	Duct Firing?	Inlet Air Chilling?
1	100%	30	no	no
2	50%	30	no	no
3	100%	60	no	yes
4	50%	60	no	yes
5	100%	60	yes	yes
6	100%	100	no	yes
7	50%	100	no	yes
8	100%	100	yes	yes

To ensure that impacts were evaluated under the operating conditions that produced the highest ambient impacts, a screening procedure was used to determine the inputs to the refined modeling. These operating cases were screened for worst-case ambient impacts on a pollutant- and averaging period-specific basis using the AERMOD model and the meteorological data described above. The results of the turbine screening analysis are presented in Appendix B, Table B-3, and are summarized in Table 16. The stack parameters and emissions rates for the turbine operating condition that produced the maximum modeled impact for each pollutant and averaging period were then used in the refined modeling analysis to evaluate the modeled impacts of the project

[7] Although the WSAC is exempt from District permitting, it has been included in the AQIA for completeness.

Table 16 **Results of Turbine Screening Procedure:** **Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period**		
Pollutant/Averaging Period		Operating Case
NOx and CO	1 hour (startup only)	Case 4
NOx, CO, SO_2 and PM_{10}	1, 3 and 8 hours 24 hours (SO_2 only) annual	Case 5
PM_{10}	24 hours	Case 7

for that pollutant and averaging period. Although only short-term NO_2 and CO impacts are required to be evaluated, all pollutants and averaging times have been included in the AQIA.

The screening analysis included both simple and complex terrain and accounted for downwash conditions at the facility. Terrain features were taken from USGS DEM data and 7.5-minute quadrangle maps of the area. For the turbine screening analysis, the coarse Cartesian grids of receptors from the original analysis were used.

2. Refined Air Quality Impact Analysis

The operating conditions and emission rates used to model GGS are shown in Table B-4, Appendix B. As discussed above, the turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case screening analysis.

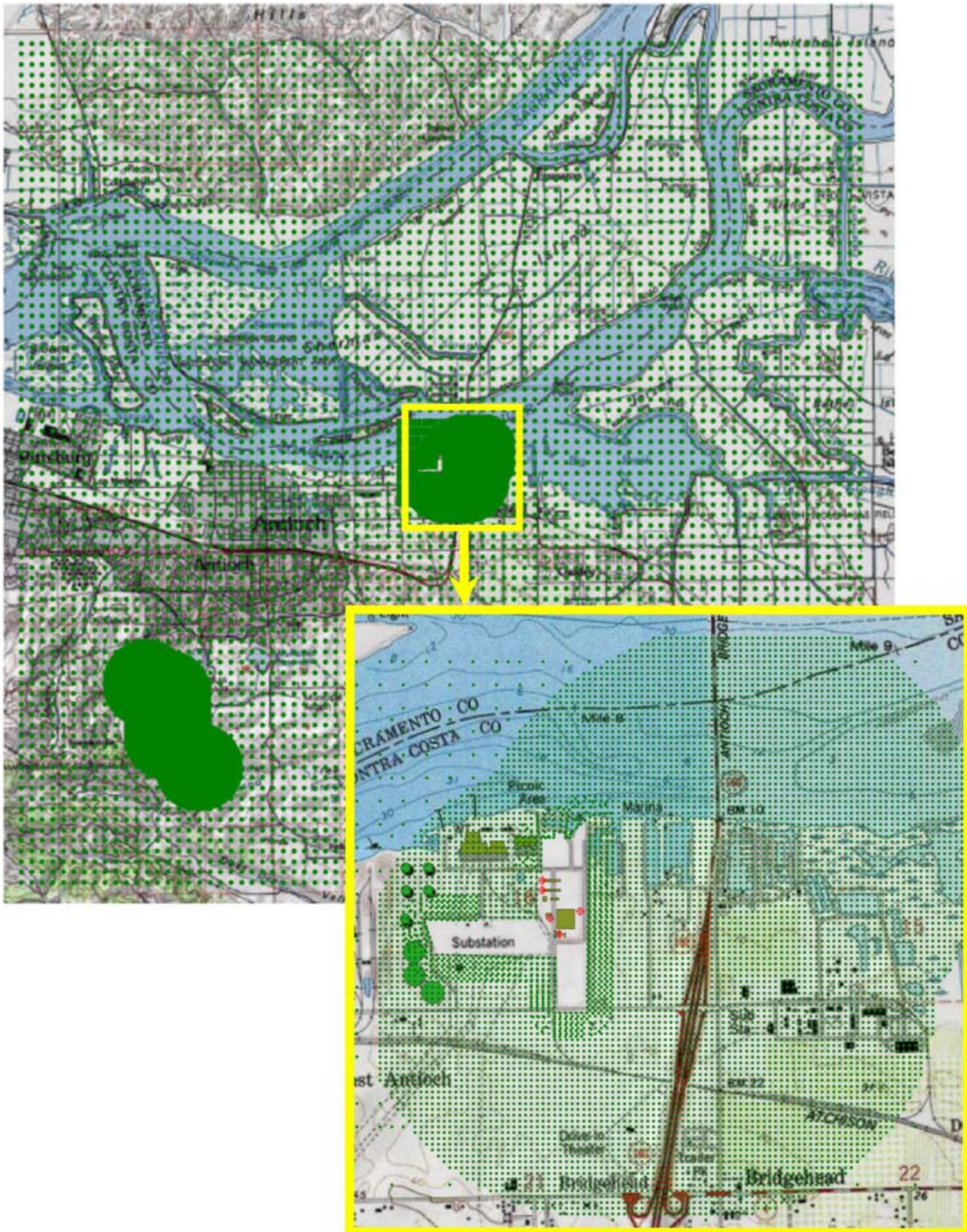
The receptor grids were derived from 7.5 minute DEM data. Twenty-five by 25 meter refined receptor grids were used in areas where the coarse grid analysis indicated modeled maxima would be located. Figure 2 shows the layout of the receptor grid.

Emissions from the permitted units were also modeled under inversion breakup fumigation and shoreline fumigation conditions, as well as during startup and commissioning, to ensure that the worst-case impacts are evaluated. These specialized air quality modeling analyses are discussed in more detail below.

Inversion Breakup Fumigation

Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time.

Figure 2
Layout of the Receptor Grid



The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Since SCREEN3 is a single-source model, each source was modeled separately and the maximum modeled concentrations were added together regardless of