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DOCKET	
09-AFC-4	
DATE	NOV 03 2010
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November 3, 2010

Mr. Pierre Martinez
Siting Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Subject: Oakley Generating Station Project (09-AFC-4)
BAAQMD Application 20798, Preliminary Determination of Compliance

Dear Mr. Martinez:

Attached please find three (3) hardcopies of the Bay Area Air Quality Management District Application 20798, Preliminary Determination of Compliance for the Oakley Generating Station (09-AFC-4).

If you have any questions about this matter, please contact me at (916) 286-0278.

Sincerely,

CH2M HILL

Douglas M. Davy, Ph.D.
AFC Project Manager

cc: POS List
Project File

October 29, 2010

Mr. Pierre Martinez, AICP
Project Manager
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814-5512

Re: Oakley Generating Station, Contra Costa County, CA
BAAQMD Application 20798

Dear Mr. Martinez:

The District has prepared a Preliminary Determination of Compliance for the proposed Oakley Generating Station.

The proposed Oakley Generating Station consists of two gas turbines, two heat recovery steam generators, one steam turbine, with associated equipment including an air-cooled condenser, a natural gas-fired auxiliary boiler, a 3-cell evaporative fluid cooler, a diesel-engine driven fire pump, and an oil-water separator. The facility would be located at 6000 Bridgehead Road, Oakley, CA 94561 in Contra Costa County.

Enclosed is a copy of the Preliminary Determination of Compliance for this proposed facility and a copy of the Notice Inviting Written Public Comment. Please submit any written comments on the intended action to the District by December 7, 2010. Please also note that the District is making available for public review the information submitted by the applicant, the District's analysis of that information, the District's preliminary decision that the project will comply with all applicable air quality regulatory requirements, and other documentation upon which the Preliminary Determination of Compliance is based. The District would be happy to forward copies of this information to your office upon request. Please note that much of the supporting information is also available electronically at www.baaqmd.gov.

If you have any questions regarding this matter, please contact Kathleen Truesdell, Air Quality Engineer II, at (415) 749-4628 (ktruesdell@baaqmd.gov).

Sincerely,

Jeff McKay
for Jack P. Broadbent
Executive Officer/APCO

Enclosure
JPB:bfc

Preliminary Determination of Compliance

Oakley Generating Station

6000 Bridgehead Road
Oakley, CA 94561

Bay Area Air Quality Management District
Application 20798

October 2010

Kathleen Truesdell
Air Quality Engineer II

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1. Introduction

The Bay Area Air Quality Management District (District) is issuing a Preliminary Determination of Compliance (PDOC) pursuant to BAAQMD Regulation 2, Rule 3, Section 403, for the Oakley Generating Station, a proposed 624-megawatt natural gas-fired electric power generation facility that would be built at 6000 Bridgehead Road in Oakley, CA. The Preliminary Determination of Compliance sets forth the District's preliminary analysis as to how the facility will comply with applicable air quality regulatory requirements, as well as proposed permit conditions to ensure compliance. The District is publishing this document for public review and comment in accordance with District Regulations 2-3-404 and 2-2-405 and -406. The District will review and consider all comments received from the public before deciding whether to issue a Final Determination of Compliance (FDOC) for the proposed project.

The proposed Oakley Generating Station project is a combined-cycle intermediate-to-baseload power plant that uses a state-of-the-art "Rapid Response" design for fast startups. This design means that the proposed facility will be able to operate efficiently both to meet contractual load and spot-sale demand for shaping or load-following generation, and on a full-time, base-loaded basis. As a combined-cycle facility, the proposed project will use Heat Recovery Steam Generators (HRSGs) to recover waste heat in the exhaust gases to make steam to generate additional power, increasing the plant's overall efficiency. This highly efficient design will allow the facility to operate efficiently when needed full-time in a base-loaded mode. In addition, the proposed project's "Rapid Response" design will allow fast startups, so that it can provide power to the grid quickly. The proposed facility will thus provide energy-efficient electric generation capacity using new conventional generation technology, with operational flexibility to efficiently address grid fluctuations due to the intermittent nature of renewable generation such as wind and solar.

The proposed project consists of two GE Frame 7FA gas turbines, two heat recovery steam generators (HRSGs), and one GE D-11 steam turbine in a combined-cycle configuration, with associated equipment including an air-cooled condenser, a natural gas-fired auxiliary boiler, a 3-cell evaporative fluid cooler, a diesel-engine driven fire pump, and an oil-water separator. More detail about the proposed facility is provided in Section 3 below (Project Description).

This PDOC sets forth the District's reasons and analysis underlying the District's preliminary determination that the project will comply with all applicable regulatory requirements relating to air quality. These requirements include applying Best Available Control Technology and providing emission offsets as described in District Regulation 2, Rule 2. This document also includes proposed permit conditions necessary to ensure compliance with applicable rules and regulations, air pollutant emission calculations, and a health risk assessment that estimates the impact of emissions from the project on public health.

This remainder of this document is organized as follows. Section 2 provides an overview of the legal framework for power plant permitting in California and describes how members of the public can learn about the project and provide input to the District and the California Energy Commission. Section 3 then proceeds to describe the proposed Oakley Generating Station project. Section 4 details the project's air emissions. Sections 5 and 6 then describe the "Best

Available Control Technology" and emissions offset requirements for the project and how the proposed facility will comply with them. Section 7 addresses two federal permitting requirements, the "Prevention of Significant Deterioration" requirement and the "Non-Attainment New Source Review" requirement for fine particulate matter, and explains how this facility is not subject to those requirements. Section 8 presents the results of the Health Risk Screening Analysis the District has conducted for the project, which found that the health risks from the project will be less than significant. Section 9 addresses other applicable legal requirements for the proposed project. Section 10 sets forth the proposed permit conditions for the project. Section 11 concludes with the District's Preliminary Determination of Compliance for the project.

2. The Power Plant Permitting Process and Opportunities for Public Participation

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 posed 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 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 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. This document presents the District's Preliminary Determination of Compliance for the proposed Oakley Generating Station. The District will solicit and consider public input on the Preliminary Determination of Compliance, and then, if the project complies with applicable air quality requirements, the District will issue a Final Determination of Compliance for use by the Energy Commission in its CEQA-equivalent environmental review. The CEC will then conduct its environmental review, and at the end of that process, it will decide whether to issue a license for the project and under what conditions.

Both the Energy Commission licensing process and the District's Determination of Compliance process relating to air quality issues provide opportunities for public participation. For the District's Determination of Compliance, the District publishes its preliminary determination – the PDOC – and invites interested members of the public to review and comment on it. This public process allows members of the public to review the District's analysis of whether and how the facility will comply with applicable regulatory requirements and to bring to the District's attention any area in which members of the public believe the District may have erred in its analysis. This process helps improve the District's final determination by bringing to the District's attention any areas where interested members of the public disagree with the District's proposal at an early enough stage that the District can correct any deficiencies before making the final determination. The Energy Commission provides similar opportunities for public participation, and publishes its proposed actions for public review and comment before taking any final actions.

At this time, the District is at the beginning of this process for the Oakley Generating Station. The District is publishing its Preliminary Determination of Compliance (PDOC) for public review and comment, and will consider comments from the public in determining whether to issue a Final Determination of Compliance (FDOC) and on what basis. The District invites all interested parties to comment in writing on any aspect of the Preliminary Determination of Compliance pursuant to District Regulation 2-3-404. Comments should be made in writing and should be directed to Kathleen Truesdell, Air Quality Engineer II, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA 94109, (415) 749-4628, ktruesdell@baaqmd.gov. Comments must be received during the comment period that begins on the date of publication and ends December 7, 2010. All comments received during the comment period will be considered by the District and addressed as necessary in any Final Determination of Compliance.

The power plant approval process also provides opportunities for members of the public to participate in person in public hearings regarding this project. The District may hold a public meeting in accordance with Regulation 2, Rule 2, Section 405 to receive verbal comment from the public if there is sufficient reason to do so. Members of the public who would like to request that the District hold a public meeting should make such a request, in writing, to Ms. Truesdell at the address set forth in the preceding paragraph prior to the end of the comment period, and should explain the reasons why a public meeting is warranted for this particular project. Members of the public will also be afforded an opportunity to participate in public hearings regarding the project at the Energy Commission as part of the Commission's environmental review process. The public hearings before the Energy Commission will encompass all aspects of the project, including air quality issues and all other environmental issues.

Interested members of the public are invited to learn more about the project as part of the public review and comment process. Detailed information about the project and how it will comply with applicable regulatory requirements are set forth in the subsequent sections of this document. All supporting documentation, including the permit application and data submitted by the applicant and all other information the District has relied on in its analysis, are available for public inspection at the District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. This Engineering Evaluation and the principal supporting documentation are also available on the District's website at www.baaqmd.gov. The public may also contact Ms. Truesdell for further information (see contact information above). **Para obtener información en español, comuníquese con Brenda Cabral en la sede del Distrito, (415) 749-4686,** bcabral@baaqmd.gov.

In addition to the District's permitting process involving air quality issues, interested members of the public are also invited to participate in the Energy Commission's licensing proceeding, which addresses other environmental concerns including those that are not related to air quality. For more information, go to the following CEC website: www.energy.ca.gov/sitingcases/oakley/. The public may also contact the Energy Commission's Public Adviser's office at:

Public Adviser
California Energy Commission
1516 Ninth Street, MS-12
Sacramento, CA 95814
Phone: 916-654-4489
Toll-Free in California: 1-800-822-6228
E-mail: PublicAdviser@energy.state.ca.us

3. Project Description

The Oakley Generating Station project is a proposed 624-megawatt combined-cycle intermediate-to-baseload power plant to be located at 6000 Bridgehead Road in Oakley, CA. This section describes the how the proposed project would function, describes where it would be located, and provides information about the specific equipment being proposed for the project.

3.1 The Oakley Generating Station's Combined-Cycle "Fast-Start" Design for Intermediate-to-Baseload Operation:

The proposed Oakley Generating Station project is a combined-cycle intermediate-to-baseload power plant, meaning that it will be able to operate efficiently to meet both contractual load and spot sale demand for electrical power, and on a full-time, base-loaded basis.[1]

The facility would be a combined-cycle power plant. In a combined-cycle plant, gas turbines burn natural gas to generate electricity, and then the heat from the gas turbine exhaust is used to produce steam in a heat recovery steam generator (HRSG) 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. Combined-cycle operation is the most efficient type of operation for a natural-gas-fired power plant, and it is typically used for base-loaded facilities that will operate full-time or near full-time. The drawback of conventional combined-cycle operation is that it takes longer for the facility to start up because the HRSG and steam turbine have to be brought up slowly to a high temperature before the plant can come on-line. Combined-cycle facilities have therefore been traditionally used for base-loaded facilities, whereas simple-cycle facilities – which use just a gas turbine and not a HRSG and steam turbine – have been used for "peaker" plants that operate only at times of peak electrical demand. Peaker plants need to come on-line quickly to be able to respond to fluctuations in demand, but they are not operated for long periods so their less-efficient design is not as great a concern.

The proposed project would overcome many of the drawbacks inherent in traditional combined-cycle operation by utilizing GE's 207FA Expedited Rapid Response Engineered Equipment Package, which is designed to have improved operational flexibility over conventional combined-cycle power plants. The Rapid Response package allows the plant to start up significantly faster than conventional combined-cycle plants by uncoupling the steam turbine as the gas turbine ramps up and comes on-line. The steam turbine is brought on-line more slowly to allow the equipment to heat up. Using this Rapid Response package, the proposed plant will be able to complete hot startups in less than 30 minutes and cold startups in less than 90 minutes. By contrast, conventional combined-cycle power plants can take up to three hours for hot startups and six hours for cold startups. The shorter startup periods of the proposed plant mean that it can come on-line and provide electricity to the grid more quickly, and also translate to reduced startup emissions; while the combined-cycle configuration retains high thermal efficiency. This fast startup capability coupled with high efficiency will give the plant a high degree of operational flexibility, which will allow it to rapidly respond to grid fluctuations that

---

[1] *See* PG&E *All Source Long-Term Request for Offers*, April 1, 2008

will result as more intermittent renewable resources are integrated into the grid while providing highly efficient generating capacity.

It should also be noted that the project would only be built if the California Public Utilities Commission (PUC) determines that there will be a need for it. The PUC recently declined to approve the project based on a determination that the facility would not be needed to meet current electrical demand projections (among other reasons).[2] In doing so, however, the PUC noted that the Oakley project "has numerous beneficial attributes" and would be an appropriate project if other projects currently under development are not actually completed for some reason. The PUC therefore expressly invited the applicant to resubmit the project for approval if another project or projects are not completed or other reasons arise showing that additional capacity is needed. Because of the possibility that the PUC may determine in the future that there is a need for the Oakley project, the CEC is going forward with its licensing proceeding for the facility and the District is developing a Determination of Compliance for use in that proceeding.

3.2 Project Location

The proposed Oakley Generating Station would be located at 6000 Bridgehead Road in Oakley, CA, on a 21.95-acre industrial site currently part of a 210-acre parcel owned by E. I. Du Pont de Nemours and Company (DuPont). To the west of the project site is the PG&E Antioch Terminal natural gas transmission hub, to the north is DuPont industrial and vacant industrial property, to the east is a DuPont's landfill area, and to the south is the Atchison, Topeka and Santa Fe railroad. Currently, the proposed site is partly in viticultural use and partly undeveloped space. The proposed project location is identified on the Project Location Map below (Figure 1). (Note that the map also identifies the locations of two other existing natural gas-fired power plants in the area, the Contra Costa Power Plant and the Gateway Generating Station, as well as the location of the recently-permitted Marsh Landing Generating Station, which is intended as a replacement for the Contra Costa Power Plant. The Contra Costa Power Plant is scheduled to shut down before the Marsh Landing Generating Station becomes operational, and before the proposed Oakley Generating Station would start operating.) An architectural rendering of the proposed project (Figure 2) and a plot plan (Figure 3) are also provided.

2 See California Public Utilities Commission Decision D1007045 on Pacific Gas & Electric Company's 2008 Long-Term Request for Offer Results and Adopting Cost Recovery and Ratemaking July 29, 2010, available at:
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/121605-03.htm#P284_61392.

FIGURE 1: PROJECT LOCATION

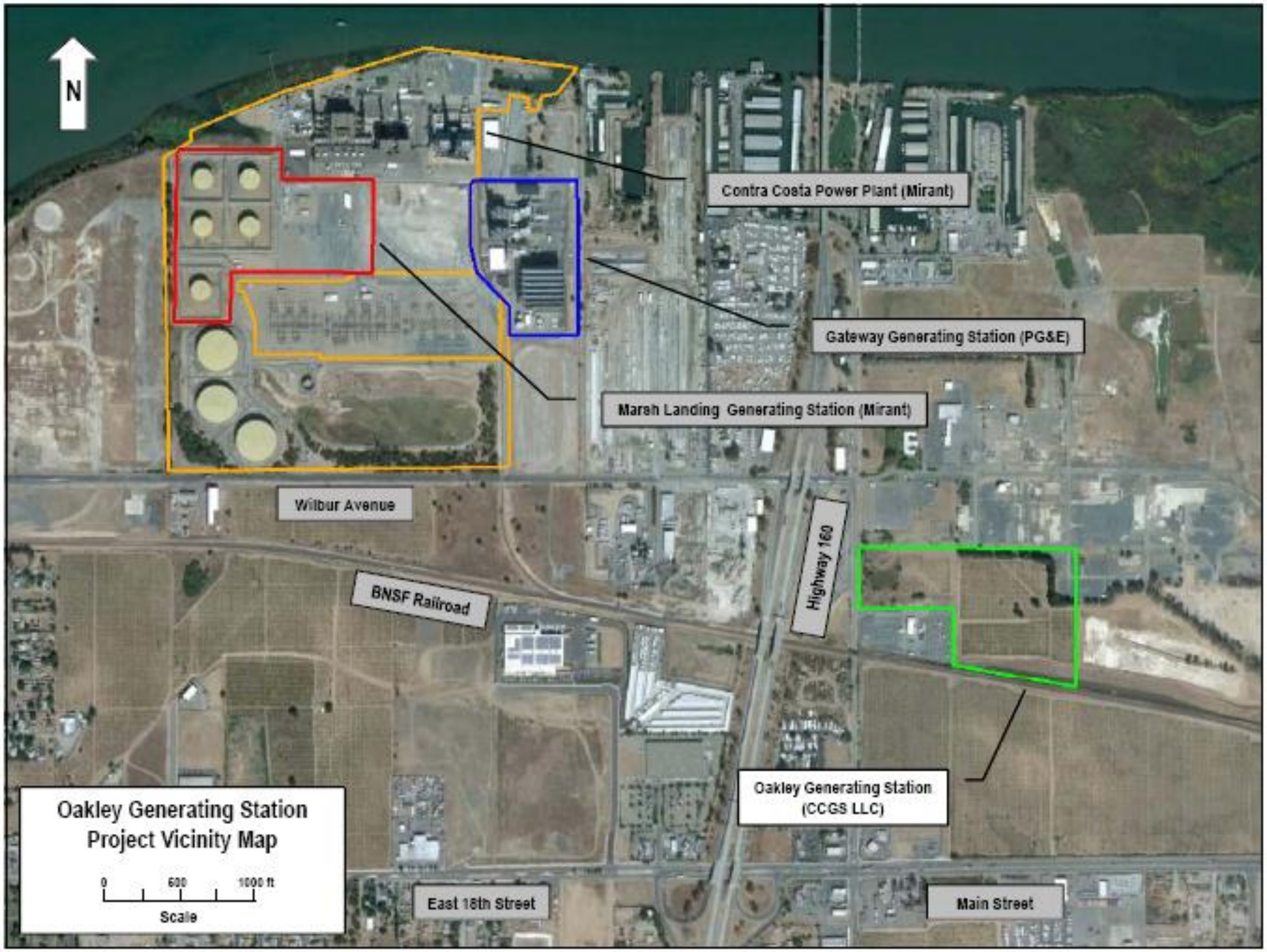
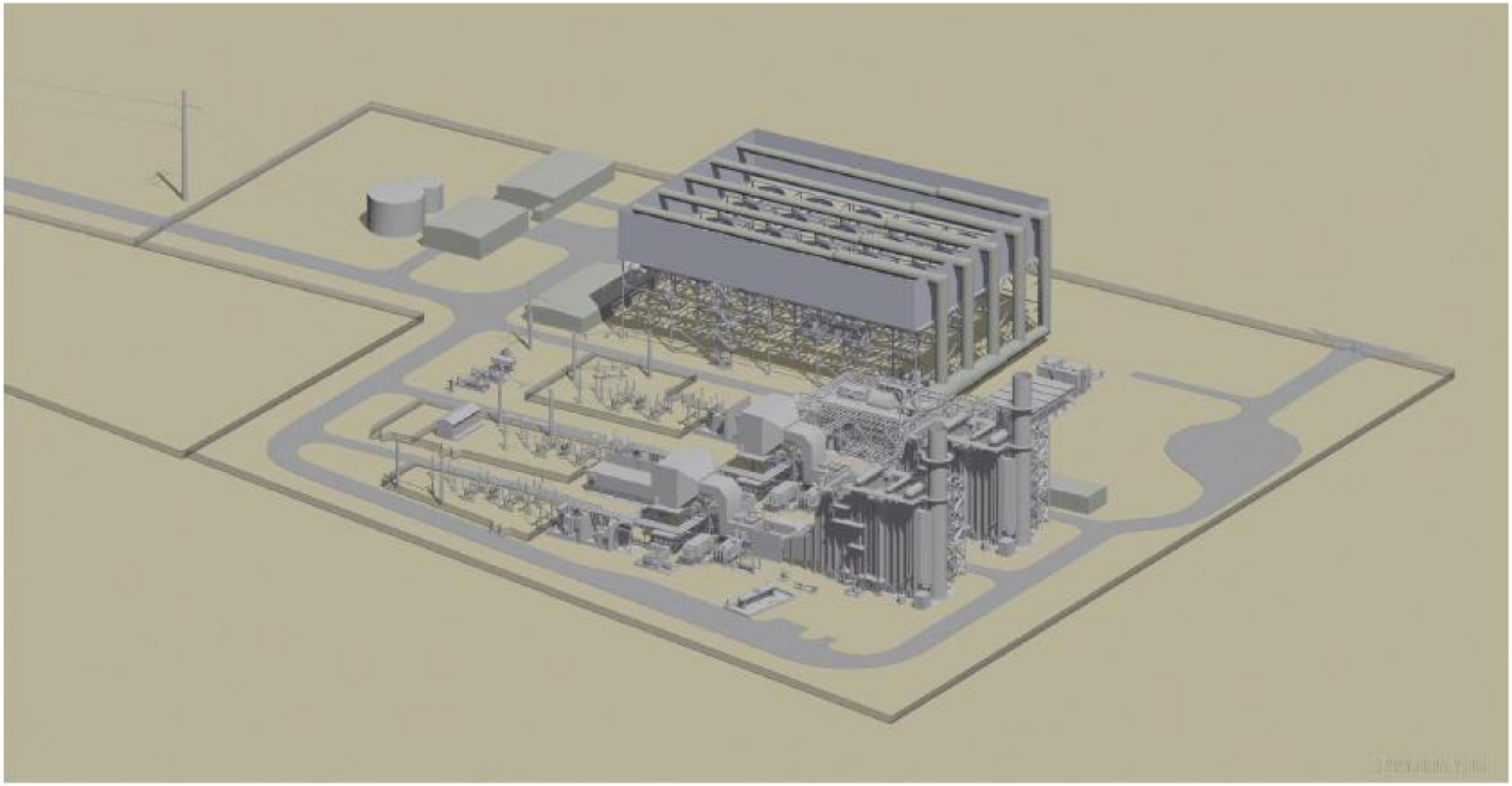


FIGURE 2: ARCHITECTURAL RENDERING



ARCHITECTURAL RENDERING
CONTRA COSTA GENERATING STATION
OAKLEY, CALIFORNIA

Source: Environmental Vision, May 2009

EY042009002SAC Figure_1.1-4.ai 06.24.09 tdaus

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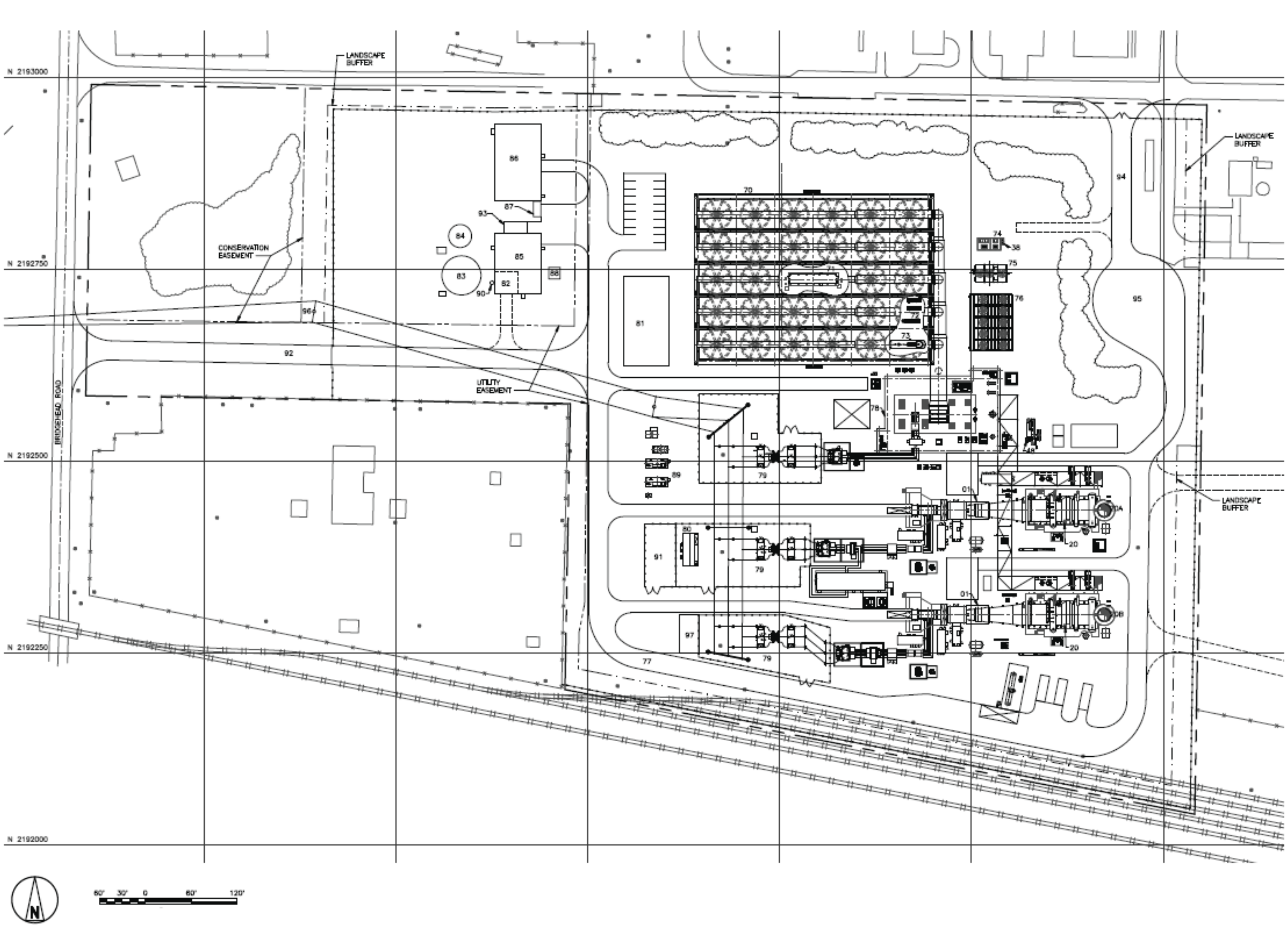
FIGURE 3: PLOT PLAN



Source: Black & Veatch Holding Company, 03/26/09, Drawing 163994-SS-1002 R1

EY042009002SAC Figure_2.1-2.ai 06.12.09 tdaus

FIGURE 3 LEGEND

FACILITIES LEGEND

ID	FACILITY	STRUCTURE HEIGHT	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
01	COMBUSTION TURBINE	70'	–	–	–
20	HEAT RECOVERY STEAM GENERATOR (HRSG)	103'	–	–	–
20A	HRSG EXHAUST STACK A	155'	2192436.00	6202665.00	CL EXHAUST STACK
20B	HRSG EXHAUST STACK B	155'	2192300.00	6202665.00	CL EXHAUST STACK
38	SAFETY SHOWER EYEWASH STATION	–	–	–	–
48	AUXILIARY BOILER	50'	2192527.61	6202572.26	CL EXHAUST STACK
70	AIR COOLED CONDENSER (ACC)	124'	–	–	–
71	ACC ELECTRICAL ENCLOSURE	14'	–	–	–
72	CONDENSER AIR EXTRACTION SKIDS	6"	–	–	–
73	ACC CONDENSATE COLLECTION TANK	28'	–	–	–
74	WET SURFACE AIR COOLER CHEMICAL FEED SKIDS	8'	–	–	–
75	WET SURFACE AIR COOLER	23'	2192744.67	6202523.00	CL COOLER
76	CLOSED CYCLE COOLING WATER HEAT EXCHANGER	19'	–	–	–
77	LOOP ROAD	–	–	–	–
78	STEAM TURBINE FOUNDATION	–	–	–	–
79	SWITCHYARD	18' & 45'	–	–	–
80	SWITCHYARD CONTROL ENCLOSURE	12'	–	–	–
81	CONTROL & ADMIN BUILDING	14'	–	–	–
82	FIRE WATER PUMP ROOM	20'	–	–	–
83	FIRE/SERVICE WATER STORAGE TANK	32'	–	–	–
84	DEMIN WATER STORAGE TANK	24'	–	–	–
85	WATER TREATMENT BUILDING	20'	–	–	–
86	WAREHOUSE/MAINTENANCE BUILDING	16'	–	–	–
87	LUBRICANT STORAGE SHED	10'	–	–	–
88	WASTE WATER LIFT STATION (IF REQUIRED)	–	–	–	–
89	GAS COMPRESSORS & GAS CONDITIONING	13'	–	–	–
90	DIESEL FIRE PUMP EXHAUST	16'	2192732.52	6201874.72	CL EXHAUST STACK
91	GAS METERING STATION	–	–	–	–
92	ACCESS ROAD	–	–	–	–
93	LEASED MIX BED EXCHANGER CONCRETE SLAB	–	–	–	–
94	EMERGENCY ACCESS ROAD	–	–	–	–
95	CUL DA SAC (TURNAROUND)	–	–	–	–
96	230KV POWER POLE	106'	–	–	–
97	OUTAGE MAINTENANCE TRAILERS AREA	–	–	–	–

NOTES

1. COORDINATES ARE BASED ON CALIFORNIA COORDINATE SYSTEM CCS83, ZONE 3. ELEVATION ARE BASED ON, NGVD 29 DATUM. BENCHMARK IS NATIONAL GEODETIC SURVEY BENCH MARK "W 563", LOCATED ADJACENT TO THE FLAGPOLE AT THE DUPONT PLANT ENTRANCE, ELEVATION = 11.168 FEET. TO OBTAIN DUPONT PLANT DATUM ELEVATION, ADD 0.70 FEET TO THE ELEVATIONS SHOWN. TOPOGRAPHIC DATA IS BASED ON AERIAL PHOTOGRAPH DATED JUNE 11, 2001. AERIAL SURVEY INFORMATION WAS OBTAINED BY RONALD GREENWELL & ASSOCIATES, INC.
2. SEE PLANT ARRANGEMENT DRAWING SM–2001, FOR LEGEND OF MAIN POWER BLOCK.
3. PROPERTY AND EASEMENT BOUNDARY INFORMATION IS BASED UPON DRAWING EXHIBIT D, BY RONALD GREENWELL & ASSOCIATES, INC. REVISION DATED 05/FEB/09.

GENERAL LEGEND

NEW FENCE

EXISTING FENCE

PROPERTY BOUNDRY (SEE NOTE 3)

EASEMENT BOUNDARY (SEE NOTE 3)

LANDSCAPE BUFFER

3.3 How the Project Will Operate

The proposed facility would generate electric power for the grid using gas turbines and a steam turbine in a combined-cycle configuration. As noted above, "combined-cycle" means that the facility generates power from burning fuel in the gas turbines directly, and then also generates additional power using the heat in the turbine exhaust by making steam to turn a steam turbine. Generating additional power from the heat in the turbine exhaust, which would otherwise be wasted, increases the facility's overall energy efficiency. This type of operation is represented schematically in Figure 4.

- Power Generating Equipment

The gas turbines generate power by burning natural gas, which expands as it burns and turns the turbine blades, which in turn rotate an electrical generator to generate electricity. The main components of the system consist of a compressor, combustor, and turbine. Each gas turbine would be equipped with an inlet air filter and an evaporative cooler to lower the temperature of the inlet air to the compressor and increase the mass of the inlet air during hot days, which increases power output. The compressor compresses 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, rotating a shaft to power the electric generator. The proposed two GE Frame 7FA gas turbines would be equipped with dry low NOx combustors to reduce NOx emissions and larger compressors than previous 7FA models.[3]

After exiting the gas turbine, the hot exhaust gases are then sent to a heat recovery steam generator (HRSG), which makes steam from the hot exhaust gases. The proposed facility would use a triple-pressure, reheat, natural circulation HRSG[4] without duct burners. Triple-pressure reheat HRSGs maximize the amount of heat extracted from exhaust gases that would otherwise be wasted and produce high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam. Under normal operating conditions, this steam is sent to a steam turbine to generate additional electricity, thereby increasing overall thermal efficiency. The reheat cycle[5] extracts more heat from the exhaust gases by reheating the cold reheat steam (steam exiting the HP section of the steam turbine) combined with superheated IP steam in the reheater sections of the HRSGs prior to being admitted to the IP section of the steam turbine. The reheat cycle makes the steam entering the IP section of the steam turbine hotter and drier, which reduces the potential for moisture erosion and increases steam turbine electrical output. Steam leaving the IP section of the steam turbine is combined with LP steam from the HRSG and enters the LP section of the steam turbine. Steam leaving the LP section of the steam turbine enters the air-cooled condenser, transfers heat to the ambient air, condenses and returns to the HRSG feedwater system.

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[3] For more information, *see* GE Energy *7FA Heavy Duty Gas Turbine Product Evolution,* at p. 4.

[4] For a detailed description of the HRSG, *see* Radback Energy, *Application for Certification Contra Costa Generating Station,* June 2009, Vol. 1, Section 2.1, at p. 2-14.

[5] For more information about the reheat cycle, see M. Boss, GE Power Systems, *Steam Turbines for STAG™ Combined-Cycle Power Systems* at p. 7-8. (available at: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3582e.pdf)

After the exhaust gases exit the HRSGs, they will be routed to post-combustion emissions control devices to treat the exhaust gases prior to exit from the stack. The proposed post-combustion emissions controls consist of a Selective Catalytic Reduction (SCR) unit to reduce oxides of nitrogen (NOx) in the exhaust and an oxidation catalyst to reduce organic compounds and carbon monoxide in the exhaust. In the SCR system, NO_x in the exhaust reacts with ammonia and oxygen in the presence of a catalyst to form nitrogen and water. 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 oxidation catalyst oxidizes the carbon monoxide and unburned hydrocarbons in the exhaust gases to form CO_2 and water. These emissions control devices are described in more detail in Section 5.

Finally, the facility would use an air-cooled condenser to condense the steam from the steam turbine and recycle it back to the HRSGs. The air-cooled condenser would take the place of the traditional wet cooling tower at other combined-cycle facilities. It would use ambient air blown by large fans across finned tubes through which the steam flows. The condensed steam (condensate) is recycled back to the HRSGs. The use of an air-cooled condenser significantly reduces the amount of water consumed by the facility.

- "Rapid Response" Startup Technology

In addition to having the higher thermal efficiency of a combined-cycle plant, the proposed facility is designed to be able to start up and dispatch quickly with GE's Rapid Response package. The Rapid Response package allows the plant to start up from warm or hot conditions in less than 30 minutes. The Rapid Response package achieves this fast performance by initially bypassing the steam turbine when the gas turbines are started up. In a conventional combined-cycle system, the gas turbine needs to be held at low load for a period of time while the HRSG is warmed up and steam is gradually fed into the steam turbine and the steam turbine is brought up to operating temperature. The steam turbine needs to be brought up to operating temperature slowly in order to minimize thermal stresses on the equipment and to maintain the necessary clearances between the rotating and stationary components of the turbine. This delay necessitated by having to slowly warm up the HRSG and steam turbine means that the gas turbine cannot increase load as rapidly as a simple-cycle gas turbine to quickly provide power to the grid. It also causes increased startup NO_x and CO emissions, because the combustion turbine needs to be held at low load – where it is not as efficient – while the HRSG and steam turbine are warmed up. The "Rapid Response" system initially bypasses the steam turbine when the combustion turbines are started, allowing them to ramp up quickly and begin providing power to the grid. The steam turbine can then be warmed up slowly without requiring the combustion turbines to be held at low load (except for a short time for cold startups), through the controlled admission of steam from the HRSGs into the steam turbine. The Rapid Response package therefore allows the facility to start up and begin providing power more quickly than a conventional system, which will enhance operational flexibility and reduce emissions associated with startups.

As part of the "Rapid Response" package, the proposed facility would also use a 50.6 MMBtu/hr natural gas-fired auxiliary boiler that would provide auxiliary steam when the plant is offline and during startups. When the plant is offline for relatively short periods, the auxiliary boiler would provide steam to be used for condensate sparging (to keep the oxygen level in the condensate low in order to prevent corrosion in the HRSG) and steam turbine seals (to maintain the seals and prevent loss of vacuum in the steam turbine and condenser) to maintain the steam turbine in a warm and ready state and expedite startups. At conventional combined-cycle plants (and at the proposed Oakley Generating Station during extended periods of shutdown), the steam turbine and condenser vacuum is released and vacuum needs to be re-established prior to startup. By eliminating these delays, the auxiliary boiler will allow the steam turbine to come on-line sooner and begin providing power to the grid.

- Additional Equipment

In addition to the two gas turbines, two HRSGs, steam turbine, air-cooled condenser, and auxiliary boiler, the Oakley Generating Station is proposed to include an evaporative fluid cooler to provide cooling water used by various equipment at the site, an oil-water separator, and a fire pump diesel engine.

The evaporative fluid cooler would be a relatively small, 3-cell heat exchanger, which extracts heat from a closed loop cooling system.[6] The closed loop cooling system provides cooling water to various plant equipment including gas turbine and steam turbine generator coolers, gas turbine and steam turbine lube oil coolers, and boiler feedwater pumps. During cool days, the evaporative fluid cooler would not be used. Instead, the closed-loop cooling water would be routed to an air-cooled heat exchanger that uses large fans to blow ambient air across the finned tubes carrying the closed-loop cooling water. During hot days when air-cooling would be insufficient to lower the temperature of the closed-loop cooling water, the evaporative fluid cooler would be used and circulating water would be sprayed over the tubes within the evaporative fluid cooler containing the closed-loop cooling water. The evaporation of the sprayed water would extract more heat from the closed-loop cooling water. Since this is a closed loop system, there is no contact between the closed-loop cooling water and the circulating water sprayed over the finned-tubes that evaporates. Water that is not evaporated would be captured in a sump at the bottom of the evaporative fluid cooler and circulated back to the top of the unit.

The proposed facility would have an oil-water separator to handle stormwater runoff from the powerblock area before discharge to the sanitary sewer system.[7] In the event that stormwater runoff picks up any liquid hydrocarbons (*e.g.*, oil), the oil-water separator would remove them so that only water is discharged into the sanitary sewer system.

The proposed facility would also have a 400 hp diesel engine to power a fire pump onsite to be used in emergencies to provide water to fight fires in the event that electricity is not available for

[6] *See* Radback Energy, *Application for Certification Contra Costa Generating Station,* June 2009, Vol. 1, Section 2.1.8.5, at p.2-26. (available at: http://www.energy.ca.gov/sitingcases/oakley/documents/applicant/afc/index.php)

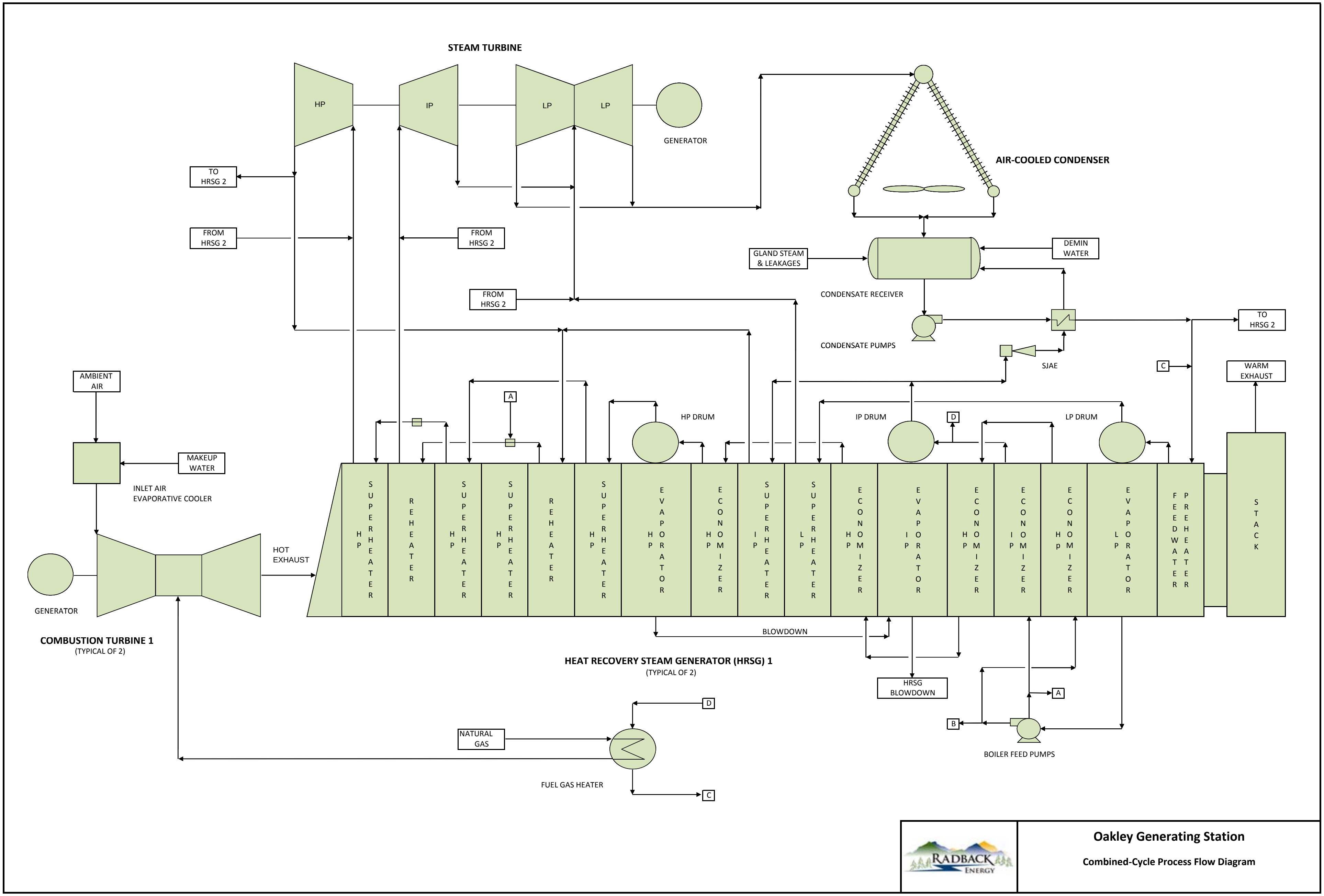
[7] *See* Radback Energy, *Application for Certification Contra Costa Generating Station,* June 2009, Vol. 1, Section 5.15, at p.5.15-14. (available at: http://www.energy.ca.gov/sitingcases/oakley/documents/applicant/afc/index.php)

the electric-motor driven fire pumps.[8] The diesel engine driven fire pump would be used in case of emergency, and would also need to be operated periodically for short periods for testing and reliability purposes.

The schematic diagram in Figure 4 below illustrates how the proposed Oakley Generating Station works.

[8] *See* e-mail from J. McLucas Radback Energy to K. Truesdell BAAQMD dated 10/6/10.

FIGURE 4: OAKLEY GENERATING STATION COMBINED-CYCLE DIAGRAM



3.4 Project Ownership

The Oakley Generating Station is being developed by Contra Costa Generating Station, LLC (Applicant), wholly owned by Radback Energy, Inc. Contra Costa Generating Station, LLC and Radback Energy, Inc., intend to sell the project after it is built to PG&E, who would own and operate the facility thereafter.

3.5 Equipment Specifications

The proposed facility would use GE's 207FA Expedited Rapid Response Engineered Equipment Package, including two GE Frame 7FA.05 natural gas-fired gas turbine-generators, each with a gross electrical output of 213 MW, and two unfired triple-steam-pressure heat recovery steam generators (HRSGs) that would feed one GE D-11 condensing steam turbine generator with a gross electrical output of 218 MW. Plant electrical auxiliary loads would be about 20 MW, so the net electrical output of the facility would be 624 MW. The proposed project also consists of an air-cooled condenser, a natural gas-fired auxiliary boiler, a 3-cell evaporative fluid cooler, a diesel-engine driven fire pump, and an oil-water separator.

The equipment that the Applicant has identified for use at the Oakley Generating Station will be identified by the following identification numbers:

S-1 Gas Turbine Generator #1, GE Frame 7FA, Natural Gas-Fired, 213 MW, 2150 MMBtu/hr (HHV) maximum rated capacity with high-efficiency inlet air filter; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Gas Turbine Generator #2, GE Frame 7FA, Natural Gas-Fired, 213 MW, 2150 MMBtu/hr (HHV) maximum rated capacity with high-efficiency inlet air filter; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-3 Auxiliary Boiler, Natural Gas-Fired, 50.6 MMBtu/hr maximum rated capacity (abated by A-5 Oxidation Catalyst if required)

S-4 Fire Pump Diesel Engine, Clarke JW6H-UFAD80 (or equivalent), 400 hp, 2.78 MMBtu/hr maximum rated heat input

S-5 Evaporative Fluid Cooler, 3-Cell, 5,880 gallons per minute (Exempt from District Permit requirements per Regulation 2, Rule 1, Section 128.4)

S-6 Oil-Water Separator, 120 gallons per hour (Exempt from District Permit requirements per Regulation 2, Rule 1, Section 103 and Regulation 8, Rule 8, Section 113)

4. Facility Emissions

This section describes the air pollutant emissions that the Oakley Generating Station will have the potential to emit, as well as the principal regulatory requirements to which the emissions will be subject. Detailed emission calculations, including the derivations of emission factors, are presented in the appendices.

4.1 Criteria Pollutants

A "criteria" air pollutant is an air pollutant for which health-based standards have been established for the amount of the pollutant in the ambient air. This section discusses the criteria air pollutants that the facility will emit, along with the facility's maximum hourly, daily, and annual emissions rates.

4.1.1 Hourly Emissions from Gas Turbines

The Oakley Generating Station's gas turbines will have the potential to emit up to the following amounts of criteria and precursor air pollutants per hour, as set forth in Table 1. These are the maximum emission rates for these air pollutants from each turbine during normal steady-state operations. Note that the emissions from the gas turbines will go to the HRSGs, where the heat in the exhaust will be used to make steam to generate additional power. The HRSGs will not fire any additional fuel, however, and so no additional emissions will be generated by them. The gas turbine emissions rates listed in this section therefore represent the emissions rates for the complete gas turbine/HRSG trains, although it is only the gas turbine equipment that actually generates the emissions. Emissions from this equipment will be measured at the stack at the end of the gas turbine/HRSG train, after abatement by the add-on control devices.

TABLE 1: GAS TURBINE STEADY-STATE EMISSIONS RATES (PER TURBINE)

Pollutant	Turbine Emissions Rate (lb/hr)
NO_x (as NO_2)	15.52
CO	9.45
POC (as CH_4)	2.71
$PM_{10}/PM_{2.5}$	7.74
SO_x (as SO_2)	6.0

Note that particulate matter from natural gas combustion sources normally has a diameter less than one micron.[9] The particulate matter will therefore be both PM_{10} (particulate matter with a diameter of less than 10 microns) and $PM_{2.5}$ (particulate matter with a diameter of less than 2.5 microns).[10]

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[9] *See* AP-42, Table 1.4-2, July 1998, at footnote c. (available at www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf).

[10] $PM_{2.5}$ is a subset of particulate matter that has recently come under heightened regulatory scrutiny. EPA has established federal regulations for $PM_{2.5}$, but they do not apply to this facility

4.1.2 Emissions During Gas Turbine Startup, Shutdown, and Tuning Operations

Maximum emissions during turbine startups and combustor tuning operations, when the turbines are at low load where they are not as efficient and when emissions control equipment may not be fully operational, are summarized in Table 2. (These operating scenarios are discussed in more detail in Section 5.2.6 below.) Table 2 shows the startup emissions and tuning emissions for each turbine. (Note that only NOx, CO, and POC emissions are affected by reduced efficiency during startups. For PM and SO_2, emission rates will not be any greater than normal operation during startup, shutdown, or tuning.)

TABLE 2: COMBINED-CYCLE TURBINE/HRSG EMISSIONS (PER TURBINE) DURING STARTUP AND TUNING OPERATIONS

Pollutant	Cold Startup (lb/event)[a]	Cold Startup (lb/hour)[b]	Hot/Warm Startup (lb/event)[c]	Hot/Warm Startup (lb/hour)[d]	Tuning (lb/event)[e]	Tuning (lb/hour)
NO_x (as NO_2)	96.3	99.9	22.3	33.9	576.0	96
CO	360.2	362.4	85.2	92.2	2,160.0	360
POC (as CH_4)	67.1	67.7	31.1	33.1	402.0	67

[a] Cold Startups not to exceed 90 minutes; by definition, occurs after turbine has been inoperative for at least 48 hours

[b] Hourly emissions with a cold startup assumes one cold startup in 45 minutes and 15 minutes of steady-state operation

[c] Hot/Warm Startups not to exceed 30 minutes; by definition, occur between 0 and 48 hours after a shutdown

[d] Hourly emissions with a hot or warm startup assumes one hot startup in 14 minutes and 46 minutes of steady-state operation

[e] Combustor tuning not to exceed 6 hours per event and 2 tuning events per year per turbine. Note that emissions rates from combustor tuning may turn out to be lower than the rates listed here, and the District will evaluate turning emissions and potentially impose lower emissions limits once the facility commences operation. See Section 5.2.6.2. for further details. The rates listed here represent worst-case emissions.

Maximum emissions during gas turbine shutdowns (also discussed in detail in Section 5.2.6) are summarized in Table 3.

TABLE 3: MAXIMUM EMISSIONS PER SHUTDOWN (PER TURBINE)

Pollutant	Shutdown Emissions Rate (lb/shutdown)[a]	Shutdown Emissions Rate (lb/hour)
NO_x (as NO_2)	39.3	46.8
CO	140.2	144.7
POC (as CH_4)	17.1	18.4

[a] Shutdowns not to exceed 30 minutes.

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as discussed in Section 7. The District is also in the process of developing regulations specifically directed to control $PM_{2.5}$, but those regulations are not in place yet. For this facility, however, the District's existing PM_{10} regulations will be equally effective in controlling $PM_{2.5}$ because all of the PM emissions from this facility will be both $PM_{2.5}$ and PM_{10}.

4.1.3 Hourly Emissions from Auxiliary Boiler

The auxiliary boiler will have the potential to emit up to the following amounts of regulated air pollutants per hour, as set forth in Table 4.

TABLE 4: AUXILIARY BOILER EMISSION RATES

Pollutant	Steady-State Emissions Rate (lb/hr)	Startup/Shutdown[a] Emissions Rate (lb/hr)	Commissioning/Tuning (lb/hr)
NO_x (as NO_2)	0.42	1.27	2.55
CO	0.37	1.11	2.22
POC (as CH_4)	0.11	0.32	0.63
$PM_{10}/PM_{2.5}$	0.35	0.35	0.35
SO_x (as SO_2)	0.14	0.14	0.14

[a] Startups make take up to one hour and shutdowns may take up to 15 minutes. Tuning required annually by District Regulation 9, Rule 7, section 313 in accordance with the procedures set forth in District Manual of Procedures, Volume I, Chapter 5.

4.1.4 Hourly Emissions from Fire Pump Diesel Engine

The fire pump diesel engine will have the potential to emit up to the following amounts of regulated air pollutants per hour, as set forth in Table 5. These are the emission rates for regulated air pollutants based on emission factors from CARB certification in Executive Order U-R-004-0369 for one hour of operation.

TABLE 5: FIRE PUMP DIESEL ENGINE EMISSION RATES

Pollutant	Fire Pump Diesel Engine Emissions Rate (lb/hr)
NO_x (as NO_2)	2.311
CO	0.592
POC (as CH_4)	0.122
$PM_{10}/PM_{2.5}$	0.105
SO_x (as SO_2)	0.004

4.1.5 Daily Facility Emissions

Maximum daily emissions of regulated air pollutants emissions for the Oakley Generating Station are set forth in Table 6 below. The table shows emissions from the gas turbines, the auxiliary boiler, and the diesel-engine driven fire pump. The table also shows emissions from the evaporative fluid cooler and oil water separator, which are both exempt from District permit requirements.

Note that for NOx, CO and POC, the daily maximum emission rates for the gas turbines are taken from the enforceable daily permit limits being proposed in condition Parts 19 and 20. The District is proposing these daily limits based on a reasonable assumption of the maximum operation likely for this equipment. The District has assumed such a reasonable maximum operating scenario to consist of one cold startup lasting 45 minutes and with the maximum permitted cold startup emissions of 96.3 lb NOx, 360.2 lb CO, and 67.1 lb POC; one shutdown lasting 30 minutes and with maximum permitted shutdown emissions of 39.3 lb NOx, 140.2 lb CO, and 17.1 lb POC; and the remaining 22.75 hours of the day in normal steady-state operation. For days on which combustor tuning occurs (limited to twice per year per turbine), 6 hours of the 22.75 steady-state operating hours were assumed to involve combustor tuning. The District has based the proposed daily emissions limits on these assumptions as a reasonable scenario of maximum foreseeable daily emissions, but it is important to note that emissions from this equipment will be limited to these emissions rates regardless of actual operating profile. This is because the emissions limitations in condition Parts 19 and 20 are enforceable permit limits, and the facility will be required to keep emissions below these levels regardless of operating profile. Thus, if for example the facility has more than one startup per day, leading to more startup emissions than the District used in its calculation of the reasonably foreseeable maximum operating scenario, the facility will be required to curtail operations to ensure that the daily maximum is not exceeded.[11]

The daily maximum emission rates for the auxiliary boiler are taken from the enforceable daily permit limits being proposed in condition Part 35. As with the turbine limits, these daily limits are based on reasonable assumptions of how the auxiliary boiler is likely to operate, but they are enforceable permit limits that the facility will be required to meet regardless of how it is operated on any particular day.

Maximum daily emissions for the diesel fire pump assume 24-hour operation in a prolonged emergency using the maximum hourly rates listed above. Maximum daily emissions from the evaporative fluid cooler are calculated from the total dissolved solids in the water, flow rate, and drift rate of the evaporative fluid cooler. Maximum daily emissions from the oil-water separator were calculated using EPA's published emission factor for this equipment using the maximum hourly operating rate and assuming 24 hours per day operation. Full details are set forth in Appendix A.

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[11] As an intermediate-to-baseload facility, the Oakley Generating Station is not expected to have multiple startups per day under normal circumstances. It is possible that on a particular day the facility could be called on to start up and shut down more than once, however. The facility will still be subject to all permit conditions in such cases, including maximum limits on hourly emissions, startup and shutdown emissions, and daily emissions.

TABLE 6: MAXIMUM DAILY REGULATED CRITERIA AIR POLLUTANT EMISSIONS FROM EACH SOURCE

	Pollutant (lb/day)				
Source	**Nitrogen Oxides (as NO_2)**	**Carbon Monoxide**	**Precursor Organic Compounds**	**Particulate Matter (PM_{10})**	**Sulfur Dioxide**
Gas Turbine (no tuning)	488	715	146	186	144
Gas Turbine (tuning)	971	2818	531	186	144
S-3 Auxiliary Boiler	9.8	9.8	2.8	8.5	3.4
S-4 Diesel Fire Pump Engine	55.5	14.2	2.9	2.5	0.1
S-5 Evaporative Fluid Cooler[a]	0	0	0	3.2	0
S-6 Oil-water separator[b]	0	0	0.6	0	0

[a] S-5 Evaporative Fluid Cooler is exempt from District Regulations per BAAQMD Regulation 2-1-128.4.
[b] S-6 Oil-water separator is exempt from District Regulations per BAAQMD Regulations 2-1-103 and 8-8-113.

These daily emission rates are used to determine which sources at the facility are subject to the requirement to use "Best Available Control Technology" pursuant to District New Source Review regulation (NSR; Regulation 2, Rule 2). Pursuant to District Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NO_x, SO_2, PM_{10}, or CO is subject to the BACT requirement for that pollutant. As Table 6 shows, the gas turbines will emit over 10 pounds per highest day of NO_x, CO, POC, PM_{10}, and SO_2, and are required to use Best Available Control Technology per Regulation 2-2-301 to limit emissions of these pollutants. The Diesel Fire Pump Engine will have the potential to emit over 10 pounds per day of NOx and CO and is required to use Best Available Control Technology to limit emissions of these pollutants.[12] The District's analysis of the Best Available Control Technology for this equipment is described in Section 5 below.

The remaining equipment at the facility is not subject to the BACT requirement in District Regulation 2, Rule 2, as none of it will emit more than 10 pounds per day of any criteria pollutant. In addition, the evaporative fluid cooler is exempt from District permitting per Regulation 2, Rule 1, Section 128.4, and the oil/water separator is exempt from District permitting per Regulation 2, Rule 1, Section 103 and Regulation 8, Rule 8, Section 113.

4.1.6 Annual Facility Emissions

The maximum annual emissions of regulated air pollutants for the proposed Oakley Generating Station project are set forth in Table 7 below. Table 7 shows the annual emissions from the

[12] Note that under normal circumstances, the diesel fire pump engine will only be operated for short periods for testing and reliability purposes. Under these circumstances, emissions of all criteria pollutants are likely to be well under 10 pounds per day. It is possible, however, that the engine would need to be operated for longer periods in the event of an emergency. The District is therefore providing worst-case emissions based on a full 24 hours per day of emergency operation.

facility, totaled for the permitted sources and for the permitted sources plus the exempt sources. Annual facility emissions for permitted sources are used to determine whether the facility will need to offset its emissions with Emissions Reduction Credits under District Regulations 2-2-202 and 2-2-203. Offsets are required for permitted sources with NO_x and POC emissions over 10 tons per year and for PM_{10} and SO_2 emissions over 100 tons per year. (Note that annual emissions are also used to determine whether additional federal permitting requirements apply. This project is not subject to any additional federal requirements because it will not emit more than 100 tons per year of any pollutant as discussed in more detail in Section 7.)

Annual emissions will be subject to enforceable permit limits to ensure that they remain below the amounts listed in Table 7. These maximum annual rates are based on estimates derived from reasonable operating scenarios that the facility is likely to experience in operation as an intermediate-to-baseload facility. Information about the operating scenarios the District used to develop these annual emissions rates is provided in the explanatory notes to Table 7, with additional details provided in Appendix A. While the District believes that these operating scenarios are realistic, it should be noted that compliance with the emissions rates listed in Table 7 does not require the facility to conform to any specific operating scenario. Because the emission rates listed in Table 7 are enforceable, not-to-exceed emissions limits in the permit, the facility will be required to monitor its emissions and ensure that they do not exceed the limits during any 12-month period. If it appears that the facility is nearing its annual limit, it will be required by law to reduce or curtail operations to ensure that emissions do not exceed the permitting annual rates.

TABLE 7: MAXIMUM ANNUAL CRITERIA AIR POLLUTANT EMISSIONS FOR THE FACILITY

	NO_2 [a] (ton/yr)	CO [b] (ton/yr)	POC [c] (ton/yr)	PM_{10} [a] (ton/yr)	SO_2 [a] (ton/yr)
Gas Turbines	98.626	98.000	29.274	63.715	12.524
Auxiliary Boiler	0.099	0.803	0.217	0.060	0.024
Diesel Fire Pump Engine	0.057	0.015	0.003	0.003	0.0001
Total subject to District Permits	98.78	98.82	29.49	63.78	12.55
Total including equipment exempt from District Permits	98.78	98.82	29.60	63.88	12.55

Notes: Exempt equipment includes Evaporative Fluid Cooler and Oil-water separator. See Appendices for Emission Calculations.

[a] Annual NOx, PM, and SO_2 emissions are based on 8,463 hours per year of operation from the turbines (including 1 cold start, 51 hot starts, 52 shutdowns), 401 hours for the auxiliary boiler (including 52 startups and 52 shutdowns), 1,500 hours per year for the evaporative fluid cooler, and 49 hours per year of maintenance and testing for the fire pump diesel engine. Gas turbine annual NOx emissions are based on expected 1.5 ppmvd; annual SO_2 emissions are based on annual average grain loading (0.25 gr/100 scf) and 1.5 lb/hr emission rate.

[b] Annual CO emissions are based on 5,390 hours per year of operation from the turbines (including 25 cold starts, 275 warm/hot starts, 300 shutdowns), 3,978 hours for the auxiliary boiler (including 300 startups and 300 shutdowns), 1,500 hours per year for the evaporative fluid cooler, and 49 hours per year of maintenance and testing for the fire pump diesel engine. Gas turbine annual CO emissions are based on expected 1.0 ppmvd.

[c] Annual POC emissions are based on 5,662 hours per year of operation from the turbines (including 1 cold start, 311 hot/warm starts, 312 shutdowns) and 3,717 hours for the auxiliary boiler (including 312 startups and 312 shutdowns), 1,500 hours per year for the evaporative fluid cooler, and 49 hours per year of maintenance and testing for the fire pump diesel engine.

These annual emissions rates show that the facility will be required to offset its emissions of NO_x and POC under District Regulation 2-2-302, because emissions will be over 10 tons per year (and for NO_x, will have to provide credits at a ratio of 1.15 tons of credits per 1 ton of emissions, because emissions will be over 35 tons per year). The facility will not be required to offset its PM_{10} and SO_2 emissions under District Regulation 2-2-303 because emissions of each of these pollutants will be less than 100 tons per year. Offset requirements are discussed in more detail in Section 6.

4.2 Toxic Air Contaminants

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 8 provides a summary of the maximum annual facility toxic air contaminant (TAC) emissions from the project.[13]

TABLE 8: MAXIMUM FACILITY TOXIC AIR CONTAMINANT (TAC) EMISSIONS

Toxic Air Contaminant	Project Emissions (lb/hour)	Project Emissions (lb/year)	Acute Risk Screening Trigger Level (lb/hr)	Chronic Risk Screening Trigger Level (lb/yr)
1,3-Butadiene	0.001	4.40	None	0.63
Acetaldehyde	5.386	4952.12	1.0	38
Acrolein	0.290	663.67	0.0055	14
Ammonia	29.321	241336.38	7.1	7,700
Benzene	0.108	463.33	2.9	3.8
Benzo(a)anthracene[a]	0.00010	0.78	None	None
Benzo(a)pyrene[a]	0.00006	0.48	None	0.0069
Benzo(b)fluoranthene[a]	0.00005	0.39	None	None
Benzo(k)fluoranthene[a]	0.00005	0.38	None	None
Chrysene[a]	0.00011	0.87	None	None
Dibenz(a,h)anthracene[a]	0.00010	0.81	None	None
Ethylbenzene	0.137	622.64	None	43
Formaldehyde	19.487	16652.10	0.12	18
Hexane	1.090	8970.54	None	270,000
Indeno(1,2,3-cd)pyrene[a]	0.00010	0.81	None	None
Naphthalene	0.007	57.49	None	3.2
Propylene	3.244	26703.82	None	120,000
Propylene Oxide	0.201	1655.57	6.8	29
Toluene	0.413	2464.76	82	12,000
Xylene (Total)	0.110	903.98	49	27,000
Sulfuric Acid Mist (H_2SO_4)	6.194	12795.41	0.26	39
Benzo(a)pyrene equivalents	0.00019	1.58	None	0.0069
Specified PAHs[b]	0.00055	4.54	None	None
Diesel Particulate Matter[c]	0.105	5.16	None	0.34
Arsenic[d]	0.000018	0.03	0.000440	0.0072
Copper[d]	0.000047	0.07	0.220000	None
Lead[d]	0.000013	0.02	None	3.2

Notes:

[13] *See* "Project TACs Summary" spreadsheet in *OGS Emissions Calcs* workbook, prepared by K. Truesdell.

[a] Polycyclic Aromatic Hydrocarbons (PAHs) impacts are evaluated as Benzo(a)pyrene equivalents.
[b] Specified PAHs are the sum of the following PAHs.

PAHs	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1.0
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

[c] Diesel Particulate Matter is a surrogate for all air toxics emitted by the diesel engine.
[d] Emitted by Evaporative Fluid Cooler

Total of Hazardous Pollutants listed in Section 112(b) of the Federal Clean Air Act = 18.7 tons/year. Section 112(b) list does not include ammonia, propylene, or sulfuric acid mist, which are included as Toxic Air Contaminants in BAAQMD Regulation 2, Rule 5. The project is not a major source of hazardous air pollutants under the Clean Air Act because emissions are less than 10 tons/year of any single hazardous air pollutant listed under Section 112(b) and less than 25 tons/year of all such hazardous air pollutants combined. Emissions from the exempt evaporative fluid cooler are included.

Table 8 is also a summary of the emissions 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 from the gas turbine SCR systems. The chronic and acute screening trigger levels shown are per Table 2-5-1 of Regulation 2, Rule 5.

If emissions are above certain established screening levels prescribed in Table 2-5-1 of Regulation 2, Rule 5, a health risk assessment is required. Where no acute trigger level is listed for a TAC, none has been established for that TAC. Based on the information contained in Table 8, a 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.

The results of the health risk assessment are discussed in full in Section 8 of this document. As explained in Section 8, the proposed facility will comply with all health risk requirements in District Regulation 2, Rule 5. Results from the health risk screening analysis indicate that the maximum cancer risk for the project as a whole is estimated at 1.56 in a million, and the maximum non-cancer risks for the project as a whole are estimated at a hazard index of 0.0832 for chronic health impacts and 0.2665 for acute health impacts. The risk from each source individually is below 1.0 in a million for the maximum individual cancer risk and below 0.02 for the maximum chronic hazard index. In accordance with the District's Regulation 2, Rule 5, the proposed Oakley Generating Station will comply with all toxic risk requirements for each individual source and for the project as a whole.

5. Best Available Control Technology (BACT)

The District's New Source Review regulations require the proposed Oakley Generating Station to utilize the "Best Available Control Technology" (BACT) to minimize air emissions, as discussed in more detail below. This section describes how the BACT requirements will apply to the facility.

5.1 Introduction

District Regulation 2-2-301 requires that the Oakley Generating Station use the Best Available Control Technology to control NO_x, CO, POC, PM_{10}, and SO_x emissions from sources that will have the potential to emit over 10 pounds per highest day of each of those pollutants. Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The gas turbines are subject to BACT under the District's New Source Review regulations (Regulation 2, Rule 2, Section 301) for NO_x, CO, POC, PM_{10}, and SO_x because each unit will have the potential to emit more than 10 pounds per highest day of those pollutants. The diesel fire pump engine will have the potential to emit over 10 pounds per day of NOx and CO in emergency situations,[14] and it is subject to BACT for these pollutants. The following sections provide the basis for the District BACT analyses for this equipment.

5.2 Gas Turbines

The following section provides the District's BACT analyses for the project's gas turbines.

5.2.1 Best Available Control Technology for Oxides of Nitrogen (NO_x)

Oxides of Nitrogen (NO_x) are a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_x 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 to form nitric oxide (NO) and nitrogen dioxide (NO_2). 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. NO and NO_2 are generally referred to collectively as "NO_x".[15] NO_x is a precursor to the formation of ground-level ozone, the principal ingredient in smog.

Control Technology Review:

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

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

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[14] Routine, non-emergency use is limited to short periods of operation for testing and reliability purposes, with emissions well under 10 pounds per day of all pollutants.

[15] 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), and NO_x can be formed by organic free radicals and nitrogen in the earliest stages of combustion (prompt NO_x). Natural gas does not contain significant amounts of fuel-bound nitrogen. Therefore, thermal NO_x is the primary formation mechanism for natural gas fired gas turbines. References to NO_x formation during combustion in this analysis refer to "thermal NO_x", which is NO_x formed from nitrogen in the combustion air.

It should be noted, however, that techniques that control NO_x by reducing combustion temperatures involve a trade-off with the formation of other pollutants. Reducing combustion temperatures to limit NO_x 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 District prioritizes NO_x reductions over carbon monoxide emissions, however, because the Bay Area is not in compliance with applicable ozone standards, but does comply with carbon monoxide standards. The District therefore requires applicants to minimize NO_x emissions to the greatest extent feasible, and then optimize CO and POC emissions for that level of NO_x control. This is a trade-off that must be kept in mind when selecting appropriate emissions control technologies for these pollutants.

The District has identified the following available combustion control technologies for reducing NO_x emissions from the gas turbines.

Steam/Water Injection: Steam or water injection was one of the first NO_x 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, 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). Water/steam injection in the gas turbines used in conjunction with Low-NO_x burners can achieve NO_x emissions as low as 25 ppm @ 15% O_2.[16]

Dry Low-NO_x Combustors: A technology that can control NO_x without water/steam injection is Dry Low-NO_x combustion technology. 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. Dry Low-NO_x combustors can achieve NO_x emissions as low as 9 ppm for frame-size turbines.[17]

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[16] M. Schorr, J. Chalfin, GE Power Systems, *Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price? GER4172*, September 1999, at p. 2 (available at: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4172.pdf)

[17] J. Kovac, Siemens Energy Inc., *Advanced SGT6-5000F Development*, Power-Gen International 2008-Orlando, Florida, at p. 8 (available at: http://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/gas-turbines-power-plants/PowerGen2008_SGT65000F.pdf)

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. Catalytic combustors such as XONON™ have not been demonstrated on large-scale utility gas turbines such as the Siemens F Class or GE Frame 7FA so the technology is not available for use at the proposed Oakley Generating Station.

Post-Combustion Controls

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

Selective Catalytic Reduction (SCR): Selective catalytic reduction is a technology that reacts the NO_x in the turbine exhaust with ammonia and oxygen in the presence of a catalyst to form nitrogen and water. NO_x 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, usually in conjunction with combustion controls. SCR has been demonstrated to be able to achieve NOx emission limits of 2.0 ppm.[18]

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 1600°F to 2100°F[19] and is most commonly used in boilers because gas turbines do not have exhaust temperatures in that range. Selective non-catalytic reduction (SNCR) requires a temperature window that is higher than the exhaust temperatures from utility gas turbine installations. The exhaust temperature from the proposed turbines ranges from approximately 1030°F to 1135°F[20], so SNCR is technically infeasible.

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 emissions for gas turbine applications (as well as CO, VOC and optionally SOx emissions). A coated catalyst oxidizes NO to NO_2 (as well as oxidizing 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

[18] *See, e.g.*, facilities listed in Table 9 below using SCR to achieve 2.0 ppm permit limits.
[19] *See* EPA *Air Pollution Control Fact Sheet*, EPA-452/F-03-031 (available at: http://www.epa.gov/ttn/catc/dir1/fsncr.pdf)
[20] *See* Radback Energy *Supplemental Filing Air Quality and Public Health Revised April 7, 2010, Application for Certification for Oakley Generating Station Project*, Appendix 5.1F, at p. 5.1F-16.

by the EMx™ process. The EMx™ catalyst requires washing and replacement periodically. EMx™ has been successfully demonstrated on several small gas turbine projects, including one on a 45 megawatt turbine. The District is not aware of any EMx™ installations on a gas turbine of the size proposed for the Oakley Generating Station (Siemens F Class or GE Frame 7FA), although the manufacturer has claimed that it can be effectively scaled up and made available for utility-scale turbines.[21]

EMx could potentially be an improvement over SCR as an add-on control device for achieving NOx reductions – assuming it can achieve the same level of NOx control – because it does not use ammonia. Ammonia has the potential, under certain atmospheric conditions, to reach with nitric acid in the atmosphere to form ammonium nitrate, which can be a form of fine particulate matter ($PM_{2.5}$). The atmospheric chemistry regarding the extent to which this process actually happens under real-world conditions has historically not been well understood, and the District's scientific understanding has been until recently that there was insufficient nitric acid in the atmosphere to make secondary $PM_{2.5}$ formation a significant concern. As a result, the District has not historically regulated ammonia as a $PM_{2.5}$ precursor, and has not found that EMx's lack of ammonia slip emissions would provide any significant benefit over SCR. The District has recently been reevaluating whether ammonia is in fact a significant contributor to secondary $PM_{2.5}$. The focus of the District's further evaluation has been a computer modeling exercise designed to predict what $PM_{2.5}$ levels will be around the Bay Area, given certain assumptions about emissions of $PM_{2.5}$ and its precursors, about regional atmospheric chemistry, and about prevailing meteorological conditions.[22] The results of this study, while still preliminary, confirm that the predominant limiting factor in the formation of secondary particulate matter is the availability of nitric acid, not ammonia. However, the study suggests that the amount of available nitric acid is not uniform, and varies in different locations around the Bay Area, and that in some locations there is available nitric acid to react with ammonia. The District's model thus predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes in ambient $PM_{2.5}$ levels of between 0% and 4%, depending on the availability of nitric acid. While this analysis is still preliminary, it suggests that that ammonia restrictions might play a role in a regional strategy to reduce $PM_{2.5}$.[23] The District is therefore evaluating whether it should impose regulations on ammonia emissions as a $PM_{2.5}$ precursor, as well as taking a harder look at whether it should require EMx as a BACT control technology for NOx reductions instead of SCR.

EMx has never been used on a large utility-scale turbine, however, and so there is no data on which to make a direct evaluation of how well the technology would work at this facility. EMx has been used on a smaller aeroderivitive turbine at the Redding Power Plant Unit No. 5, a 45-

[21] *See* EmeraChem, High Performance EMx™ Technology For Fine Particles, NOx, CO, and VOCs From Gas Turbines and Stationary IC Engines (EMx White Paper), May 2008 at p. 15. (available at: http://www.emerachempower.com/index.php?section=downloads&id=10)
[22] *See* BAAQMD, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Preliminary Report, Oct. 1, 2009), at p. 8 (Preliminary PM2.5 Modeling Report). (available at: http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Research%20and%20Modeling/PM-data-analysis-and-modeling-report.ashx)
[23] Preliminary $PM_{2.5}$ Modeling Report at pp. E-3 – E-4.

MW combined-cycle facility in Shasta County, CA. The data from that facility show that EMx cannot readily keep emissions as low as 2.0 ppm, which SCR can easily achieve. The Shasta County Air Quality Management District evaluated EMx™ at the Redding facility under a demonstration NO_x limit of 2.0 ppm. After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EMx™, and concluded that "Redding Power is not able to reliably and continuously operate while maintaining the NO_x demonstration limit of 2.0 ppmvd @ 15% O_2."[24] Although the manufacturer maintains that such problems have been overcome, concerns remain about how consistently the technology would be able to perform. Recent communications with the Shasta County Air District confirm that the earlier conclusions about the achievability of a lower limit remain valid.[25] In addition, monthly reports of Continuous Emissions Monitoring System (CEMS) data submitted by Redding Power Plant to Shasta County Air District during the past three calendar years indicate that emissions have often been substantially higher.[26] Furthermore, the data from Redding are from a smaller aeroderivitive turbine, and there is no guarantee that if it were scaled up for use on utility-size turbines that it would even be able to achieve the performance of the Redding Power facility. For all of these reasons, it is clear that EMx is not as developed as SCR at this time and cannot achieve the same level of emissions performance that SCR is capable of.

Proposed BACT Control Technology for NO_x for Gas Turbines:

The Applicant has proposed the use of Dry Low-NO_x combustors and SCR as BACT for the combined-cycle gas turbines. As explained above, these are the most effective combustion and pot-combustion control technologies available for this type of facility. These emissions control technologies therefore satisfy the District's BACT requirement.

Proposed BACT Emissions Limit for NO_x for Gas Turbines:

The District is also proposing to establish a BACT emissions limit in the permit of 2.0 ppmvd @ 15% O_2 (averaged over one hour), which is the most stringent limit that has been achieved in practice at any other similar facility and is the most stringent limit that would be technologically feasible.

To determine the most stringent emissions limit that has been achieved in practice, the District evaluated other similar combined-cycle gas turbines. The District reviewed the NO_x emissions limits of power plants using large turbines in a combined-cycle mode abated by SCR systems. The District reviewed BACT determinations at the EPA RACT/BACT/LAER Clearinghouse, ARB BACT Clearinghouse and recent projects listed by the CEC as approved or under construction. The combined-cycle facilities with the most stringent permit limits, as listed in these databases, are shown in the table below.

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[24] Letter from R. Bell, Air Quality District Manager, Shasta County Air Quality Management District, to R. Bennett, Safety & Environmental Coordinator, Redding Electric Utility, June 23, 2005.

[25] See Memorandum of Record of Telephone call to Shasta County dated 10/25/2010, prepared by W. Lee BAAQMD.

[26] *See* Redding Unit 5 NOx CEM summary (SCONOx) 2007-2008.

TABLE 9: NO_x EMISSION LIMITS FOR LARGE GAS TURBINES IN COMBINED-CYCLE POWER PLANTS

Facility Name	RBLC ID or CEC Docket #	NOx ppmvd @ 15% O2 (averaging period)
Lawrence Energy	OH-0248	3.0
Longview Energy Development	WA-0288	3.0 (24-hr); 2.5 (12-month)
Middleton Facility	ID-0010	3.0 (24-hr) without duct firing; 3.5 (24-hr) with duct firing; 2.5 (12-month) all modes
Wansley Combined Cycle Energy Facility	GA-0102	3.0
Augusta Energy Center	GA-0093	3.0
Delta - Calpine	1998-AFC-03	2.5 (1-hr)
Moss Landing - L.S. Power	1999-AFC-04	2.5 (1-hr)
La Paloma - Complete Energy Holdings	1998-AFC-02	2.5 (1-hr)
Los Medanos - Calpine	1998-AFC-01	2.5 (1-hr)
Pastoria - Calpine	1999-AFC-07	2.5 (1-hr)
Gateway - PG&E	2000-AFC-01	2.5 (1-hr)
High Desert - Constellation	1997-AFC-01	2.5 (1-hr)
Sutter - Calpine	1997-AFC-02	2.5 (1-hr)
Blythe I - NextEra Energy (FPL)	1999-AFC-08	2.5 (1-hr)
Elk Hills - Sempra & Oxy	1999-AFC-01	2.5 (1-hr)
Metcalf - Calpine	1999-AFC-03	2.5 (1-hr)
COB Energy Facility, LLC	OR-0039	2.5 (4-hr)
Wallula Power Plant	WA-0291	2.5 (3-hr)
McIntosh Combined Cycle Facility	GA-0105	2.5
Cogen Technologies Linden Venture, L.P.	NJ-0059	2.5
Empire Power Plant	NY-0100	2.0 (3-hr) without duct firing; 3 (3-hr) with duct firing
FPL Turkey Point Power Plant	FL-0263	2.0 (24-hr)
Otay Mesa - Calpine	1999-AFC-05	2.0 (1-hr), allows 15 1-hr excursions for transient load etc.
Mountainview	2000-AFC-02	2.0 (1-hr), allows 15 one-hour excursions for transient load etc.
Cosumnes - SMUD	2001-AFC-19	2.0 (1-hr); 30 (1-hr) transient load
Palomar Escondido - SDG&E	2001-AFC-24	2.0 (1-hr); 2.0 (3-hr) with duct firing or transient hour of +25 MW
Sacramento Municipal Utility District	CA-0997	2.0
PSEG Fossil LLC Linden Generating Station	NJ-0058	2.0
Warren County Facility	VA-0308	2.0
Warren County Facility	VA-0308	2.0
Warren County Facility	VA-0308	2.0
Tracy Substation Expansion Project	NV-0035	2.0 (3-hr)
Copper Mountain Power	NV-0037	2.0 (3-hr)
Sumas Energy 2 Generation Facility	WA-0315	2.0 (3-hr)
Magnolia - So. Ca. Power Producers	2001-AFC-06	2.0 (3-hr)
Goldendale Energy, Inc.	WA-0302	2.0 (3-hr)
La Paz Generating Facility, Siemens option	AZ-0049	2.0 (3-hr) changes to (1-hr) after 18 months
La Paz Generating Facility, GE option	AZ-0049	2.0 (3-hr) changes to (1-hr) after 18 months
Wellton Mohawk Generating Station, Siemens-Westinghouse 501F option	AZ-0047	2.0 (3-hr) changes to (1-hr) after 18 months
Wellton Mohawk Generating Station, GE 7FA option	AZ-0047	2.0 (3-hr) changes to (1-hr) after 18 months

Facility Name	RBLC ID or CEC Docket #	NOx ppmvd @ 15% O2 (averaging period)
Ivanpah Energy Center, L.P.	NV-0038	2.0 (1-hr) without duct firing; 13.96 lb/hr with duct firing
Gila Bend Power Generating Station	AZ-0038	2.0 (1-hr)
El Segundo Repower - NRG	2000-AFC-14	2.0 (1-hr)
Victorville Hybrid Gas-Solar - City of Victorville	2007-AFC-1	2.0 (1-hr)
Duke Energy Arlington Valley	AZ-0043	2.0 (1-hr)
Colusa II Generation Station - PG&E Final Decision	2006-AFC-9	2.0 (1-hr)
Lodi Energy Center - NCPA	2008-AFC-10	2.0 (1-hr)
Avenal Energy - Avenal Power Center, LLC	2008-AFC-1	2.0 (1-hr)
Russell City - Calpine & GE	2001-AFC-07	2.0 (1-hr)
CPV Warren	VA-0291	2.0 (1-hr)
Kleen Energy Systems, Inc.	CT-0151	2.0 (1-hr)
IDC Bellingham [a]	CA-1050	2.0/1.5 (1-hr)

[a] The IDC Bellingham facility in Massachusetts, was permitted with a two-tiered NOx emissions limit that imposed an absolute not-to-exceed limit of 2.0 ppm but also required the facility to maintain emissions below 1.5 ppm during normal operations. (Note also 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 Oakley Generating Station is expected to exhibit the same type of variation in emissions under the various operating scenarios it will face, and it is expected to have emissions below 2.0 ppm at times but will have emissions as high as 2.0 ppm under some circumstances. The District is therefore proposing a 2.0 ppm limit to ensure that the limit will be achievable under all operating conditions.

As Table 9 shows, emissions of 2.0 ppm NO_x averaged over 1-hour is the most stringent emission limitation that has been determined to be achievable at any similar facility using SCR for NO_x control.

The District also considered whether it would be feasible to implement a NO_x permit limit below 2.0 ppm. Consistent compliance with a limit below 2.0 ppm has never been demonstrated in practice, and the equipment vendors that the District contacted regarding this issue stated that they would not be able to guarantee that a lower limit could be achieved.[27] The District nevertheless considered whether it would be technologically feasible to do so. The District has concluded that imposing a NOx emissions limit below 2.0 ppm cannot be justified as BACT at this time.

Additional NOx reductions could potentially be achieved by increasing the amount of catalyst or size of the catalyst bed in the SCR system. It would be difficult to achieve any substantial additional reductions, however, because at the very low NOx levels that are currently being achieved by SCR additional efforts produce diminishing returns. SCR performance for NO_x control is highly dependent on the NO_x to ammonia reaction stoichiometry. At stoichiometric

[27] *See, e.g.,* Letter from T. Pintcke, Vice President, Black & Veatch, to K. Truesdell, Air Quality Engineer, Bay Area Air Quality Management District, Oct. 11, 2010, stating that Black & Veatch "sees no basis for and will not guarantee an hourly limit for NO_x emissions below 2 ppm for any averaging period."

conditions, there would be just enough ammonia to react with the NO_x with no additional ammonia slip exhausted out the stack. It becomes highly challenging to ensure a uniform distribution of ammonia to NO_x over the entire gas turbine operating range when NOx concentrations are very low. Alternatively, some vendors have considered staging two separate ammonia injection grids and catalyst beds in series in order to achieve an optimal distribution of ammonia to NO_x that might maintain emissions at less than 2.0 ppm NO_x over the entire gas turbine operating range. But this approach has its own drawbacks, such as increasing the backpressure on the turbine exhaust and decreasing the efficiency of the turbine resulting in higher emissions per megawatt of power generated. Moreover, no installation using a staged series of ammonia injection grids has been demonstrated in practice. Additionally, temperature variations across the catalyst bed also impact SCR performance. At progressively lower NOx concentrations, these variations have an increasingly significant impact on maintaining stoichiometric conditions. For all of these reasons, it becomes increasingly difficult to gain additional NOx reductions as concentrations are driven to extremely low levels simply by increasing the amount of catalyst or the size of the catalyst bed. Increasing the amount of catalyst or size of catalyst bed theoretically can provide for more NOx reduction, but for a number of reasons simply adding more catalyst reaches a point of diminishing returns as NOx levels approach zero.[28]

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

Finally, assuming that an SCR system could be designed to achieve emissions below 2.0 by increasing the amount of catalyst or the size of the catalyst bed, the system would have to be able to operate to maintain compliance at all times, including during periods transient load. Compliance is much more difficult during such periods because the SCR system's ammonia injection control system is limited in how quickly it can respond to rapidly changing conditions. The amount of ammonia being injected is determined based on turbine operating conditions and the NO_x concentration at the stack exhaust. There is an optimal amount of ammonia based on the incoming NO_x and the ammonia injection system provides a slight excess to ensure the NO_x

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

emissions are minimized while ammonia slip levels are also minimized. When gas turbine load is ramped quickly, its NOx emissions can change much more rapidly than the ammonia injection system can respond due to the lag time in the ammonia injection control system and the NO_x continuous emission monitor. This control system lag and continuous emission monitor (CEM) lag time make meeting a permit limit below 2.0 ppm NO_x averaged over one hour much more difficult during rapid load changes.

Designing an SCR system to consistently maintain compliance with a limit below 2.0 ppm would also be more difficult because transient load conditions and fast ramp rates are expected to become more common in the coming years as California moves to more renewable power generation. Renewable sources of electrical power such as wind and solar are much more intermittent and uncertain that traditional power plants. Fossil fuel fired plants will be needed to fill in the gaps when the sun is not shining or the wind is not blowing, and they will be required to ramp up quickly when needed and then ramp back down when renewable sources come back on-line.[29] For this reason, facilities such as the Oakley Generating Station are expected to experience a significantly increased amount of transient load conditions, although it is difficult to predict with certainty exactly how these facilities will need to operate. An SCR system would need to be designed to operate at a very high degree of efficiency in order to ensure that it would be able to maintain compliance with a short-term NOx limit below 2.0 during all potential transient load conditions. Moreover, given the uncertainty as to how exactly the facility will need to operate in support of additional renewable generation, it would be difficult to predict the maximum design parameters that would be needed to ensure compliance.

Based on all of this analysis, the District has concluded that there is insufficient evidence on which to make a determination that a NOx emissions limit can be justified as BACT for this facility. Although it may be possible in theory to design an enhanced SCR system that could potentially be more effective in reducing NOx, there is substantial uncertainty as to how effective such an enhanced system would actually be in consistently achieving a lower permit limit. Moreover, even if a lower limit could theoretically be achieved, there is substantial uncertainty over how the SCR system would need to be designed to do so given the changes in power plant operating scenarios that are expected as California moves to more renewable power sources, and in particular the greater incidence of transient load conditions. The District is also concerned that if the facility is subjected to a lower limit and finds that it cannot achieve it during transient loads, the facility would not be able to be operated to support renewable resources as readily, which would hinder California's efforts to develop those resources. And finally, the District is also mindful of the additional costs and ancillary adverse environmental impacts that would be associated with an enhanced SCR system. Although additional costs and ancillary impacts can be acceptable where justified by the increased effectiveness of a better add-on control system under a BACT analysis, there is little clear indication that additional NOx reductions beyond the very stringent 2.0 ppm levels that are currently being achieved would be worth it here (to the extent that any additional reductions could even be obtained in practice). Given the high degree of uncertainty regarding what level of additional NOx reductions could actually be achieved, what would be required from a technical standpoint to achieve any such

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

additional reductions, and what the adverse ancillary impacts would be, the technical information available at this point does not provide a sufficiently certain basis to support a BACT determination that a NOx emissions limit below 2.0 should be required. The District has considered all of this evidence and has concluded that it does not support imposing a NOx emissions limit below 2.0 ppm as BACT for this project.

The District has therefore determined that 2.0 ppmvd at 15% O_2, averaged over 1-hour, is the BACT emission limit for NO_x for the combined-cycle gas turbines. The District is also proposing corresponding hourly mass emissions limits. Compliance with the NO_x permit limits will be demonstrated on a continuous basis using a continuous emissions monitor.

5.2.2 Best Available Control Technology for Carbon Monoxide (CO)

Carbon monoxide is a colorless odorless gas that is a product of incomplete combustion.

Control Technology Review:

As with NO_x, the 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 District prioritizes NO_x control over carbon monoxide control because the Bay Area is not in compliance with state and federal standards for ozone, which is formed by NO_x emissions reacting with other pollutants in the atmosphere. The District therefore does not favor increasing combustion temperatures to control carbon monoxide. Instead, the District favors approaches that reduce NO_x to the lowest achievable rate and then optimize carbon monoxide emissions for that level of NO_x emissions.

Good Combustion Practice: The District has identified good combustion practice as an available combustion control technology for minimizing carbon monoxide formation during combustion. Good combustion practice utilizes "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 achieve complete combustion, thus minimizing CO emissions. Good combustion practice can be used with the low-NO_x combustion technology selected for minimizing NO_x emissions (Dry Low-NO_x Combustors).

Post-Combustion Controls

The 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 turbines to abate CO and POC emissions.

EMx™: EMx™, described above in the NO_x 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 NO_x reduction device. Hence, it is identified as a device separate from the oxidation catalyst. EMx™ is not as effective as SCR in achieving NOx reductions, however, and so the District rejected it as a BACT control technology.

Proposed BACT Control Technology for CO for Gas Turbines:

Based on the foregoing discussion, the District has determined that the proposed combination of good combustion practice to reduce the formation of carbon monoxide during combustion and an oxidation catalyst to remove carbon monoxide from the gas turbines exhaust satisfies the BACT requirement.

Proposed BACT Emissions Limit for Carbon Monoxide (CO) for Gas Turbines:

The District is also proposing a CO BACT limit of 2.0 ppmvd @ 15% O_2 (1-hour average), which is the most stringent that has been achieved in practice at other similar combined-cycle facilities and is the most stringent limit that is technologically feasible and cost-effective.

To establish what level of emissions performance has been achieved in practice for this type of facility, the District reviewed the CO emissions limits of other large combined-cycle power plants using oxidation catalyst systems. As with the NO_x comparison set forth above, the District reviewed BACT determinations for CO at the EPA RACT/BACT/LAER Clearinghouse, ARB BACT Clearinghouse and recent projects listed by the CEC as approved or under construction. The combined-cycle facilities with the most stringent permit limits, as listed in these databases, are shown in the table below.

TABLE 10: CO EMISSION LIMITS FOR LARGE GAS TURBINES IN COMBINED-CYCLE POWER PLANTS

Facility Name	RBLC ID or CEC Docket #	CO ppmvd @ 15% O2 (averaging period)
FPL Turkey Point Power Plant	FL-0263	14.1 (24-hr) with duct firing and power aug; 6.0 (all modes) annual average
Delta – Calpine	1998-AFC-03	10 (3-hr)
La Paloma - Complete Energy Holdings	1998-AFC-02	10 (3-hr) if < 221 MW, or 6.0 (3-hr) if > 221 MW
Moss Landing - L.S. Power	1999-AFC-04	9.0 (3-hr)
Pastoria – Calpine	1999-AFC-07	6.0 (3-hr)
Gateway - PG&E	2000-AFC-01	6.0 (3-hr)
Los Medanos – Calpine	1998-AFC-01	6.0 (3-hr)
Otay Mesa – Calpine	1999-AFC-05	6.0 (3-hr)
Mountainview	2000-AFC-02	6.0 (1-hr)
Longview Energy Development	WA-0288	6.0 (1-hr); 2.0 (12-month)
Middleton Facility	ID-0010	5.0 (1-hr), 2.0 (12-month)
Sacramento Municipal Utility District	CA-0997	4.0
High Desert – Constellation	1997-AFC-01	4.0 (24-hr)
Blythe I - NextEra Energy (FPL)	1999-AFC-08	4.0 (3-hr)
Sutter – Calpine	1997-AFC-02	4.0 (3-hr)
Cosumnes – SMUD	2001-AFC-19	4.0 (3-hr)
Elk Hills - Sempra & Oxy	1999-AFC-01	4.0 (3-hr)
Metcalf – Calpine	1999-AFC-03	4.0 (3-hr)
Palomar Escondido - SDG&E	2001-AFC-24	4.0 (3-hr)
Gila Bend Power Generating Station	AZ-0038	4.0 (3-hr)
Ivanpah Energy Center, L.P.	NV-0038	4.0 (1-hr) without duct firing; 17 lb/hr with duct firing
El Segundo Repower – NRG	2000-AFC-14	4.0 (1-hr)
Tracy Substation Expansion Project	NV-0035	3.5 (3-hr)
La Paz Generating Facility, Siemens option	AZ-0049	3.0 (3-hr)
La Paz Generating Facility, GE option	AZ-0049	3.0 (3-hr)
Wellton Mohawk Generating Station, Siemens-Westinghouse 501F option	AZ-0047	3.0 (3-hr)
Wellton Mohawk Generating Station, GE 7FA option	AZ-0047	3.0 (3-hr)
Copper Mountain Power	NV-0037	3.0 (3-hr)
Duke Energy Arlington Valley	AZ-0043	3.0 (3-hr)
Colusa II Generation Station - PG&E Final Decision	2006-AFC-9	3.0 (3-hr)
Lawrence Energy	OH-0248	2.0 without duct firing; 10.0 with duct firing
Victorville Hybrid Gas-Solar - City of Victorville	2007-AFC-1	2.0 (1-hr) without duct firing; 3.0 (1-hr) with duct firing
Wansley Combined Cycle Energy Facility	GA-0102	2.0
Augusta Energy Center	GA-0093	2.0
McIntosh Combined Cycle Facility	GA-0105	2.0
Cogen Technologies Linden Venture, L.P.	NJ-0059	2.0
PSEG Fossil LLC Linden Generating Station	NJ-0058	2.0
COB Energy Facility, LLC	OR-0039	2.0 (4-hr)
Avenal Energy - Avenal Power Center, LLC	2008-AFC-1	2.0 (3-hr)
Wallula Power Plant	WA-0291	2.0 (3-hr)
Lodi Energy Center - NCPA	2008-AFC-10	2.0 (3-hr)
Magnolia - So. Ca. Power Producers	2001-AFC-06	2.0 (1-hr)

Facility Name	RBLC ID or CEC Docket #	CO ppmvd @ 15% O2 (averaging period)
Sumas Energy 2 Generation Facility	WA-0315	2.0 (1-hr)
Goldendale Energy, Inc.	WA-0302	2.0 (1-hr)
IDC Bellingham	CA-1050	2.0 (1-hr)
Russell City - Calpine & GE	2001-AFC-07	2.0 (1-hr)
Warren County Facility [a]	VA-0308	1.8 without duct firing; 2.5 with duct firing
CPV Warren [a]	VA-0291	1.3 without duct firing; 1.8 with duct firing and power aug
Warren County Facility [a]	VA-0308	1.3 without power aug.
Warren County Facility [a]	VA-0308	1.3 without duct firing; 1.2 with duct firing
Kleen Energy Systems, Inc. [b]	CT-0151	0.9 (1-hr) without duct firing

Notes:
[a] Warren County Facility and CPV Warren are the same facility (Permit Number 81391) and have not been built; a new application amended April 27, 2010, by Virginia Electric Power and Power Company (Dominion) is under review and will replace the listed determinations.
[b] Kleen Energy Systems has not yet been operated.

Based on the facilities that the District has reviewed, the most stringent permit limit that has been achieved in practice by any other similar facility is 2.0 ppmvd @ 15% oxygen averaged over one hour. Permits issued for two facilities – the Warren County facility and the Kleen Energy Systems facility – included some limits of less than 2.0, but neither of these facilities has actually come online yet and so there is no operating data available on which to assess whether they will actually be able to meet these lower limits. The fact that permits have been issued with limits below 2.0 ppm does not establish that such lower limits have actually been "achieved" as that term is used in the BACT definition where there is no evidence from actual operations demonstrating that the facilities have in fact been operating in compliance with these permit limits. As the District's BACT guidelines explain, an "achieved in practice" emissions limit is "the most stringent emission limit achieved in the field for the type and capacity of equipment comprising the source under review and operating under similar conditions, e.g. process throughput and material usage, hours of operation, site-specific limitations and opportunities, etc. For example, the control device performance or emission limit has already been verified by source tests or other appropriate documentation approved by this District or another California air district."[30] Where a limit has simply been included in a permit, but the facility had not been built and emissions have not been verified as being in compliance with the limits, the limits are not "achieved in practice" for purposes of the District BACT requirement. The lowest permit limit that has actually been achieved in practice is 2.0 ppm averaged over one hour.

The District also considered whether it would be technically feasible and cost-effective to require the proposed facility to meet an emission limit below the 2.0 ppm level that has been achieved for similar combined-cycle facilities. The District found that although it may be technically feasible to do so, it would not be cost-effective to do so given the magnitude of the costs involved. Additionally, a larger catalyst capable of meeting a CO permit limit below 2 ppm may have other implementation problems such as a high back pressure, which could adversely impact turbine operating performance and efficiency.

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[30] BAAQMD BACT/TBACT Workbook, "Guidelines For Best Available Control Technology", Section 3 ("Policy and Implementation Procedure"), subsection 1 ("Interpretation of BACT"), available at http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

The District evaluated the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining emissions below 1.0 ppm. Based on these analyses, the cost of achieving a 1.0 ppm permit limit would be an additional $77,882 per year (above what it would cost to achieve a 2.0 ppm limit), and the additional reduction in CO emissions would be approximately 20.11 tons per year, making an incremental cost-effectiveness value of over $3,874 per ton of additional CO reduction.[31] Moreover, the total cost of achieving a 1.0 ppm CO limit (as opposed to the incremental costs of going from 2.0 ppm to 1.0 ppm) would be over $524,959 per year, and the total emission reductions from 9.0 ppm from the turbine to a 1.0 ppm limit would be 121.01 tons per year, resulting in a total (or "average") cost effectiveness value of $4,338. Based on these costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.0 ppm CO permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 1.0 ppm limit would be more expensive, on a per-ton basis, than what other similar facilities are required to achieve. The District has not adopted its own cost-effectiveness guidelines for CO,[32] but a review of guidelines adopted by other districts in California and of BACT determinations made by agencies around the country found that additional CO controls are not normally required where the cost per ton exceeds a few hundred to a few thousand dollars per ton.[33] Additional CO reductions here would not be justified as BACT given these costs.

The District has therefore determined that BACT for CO for this facility is the use of good combustion practice with abatement by an oxidation catalyst, and a permit limit of 2.0 ppmvd @ 15% O_2, averaged over 1-hour. The District is also proposing corresponding hourly mass

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[31] *See OGS Cost effectiveness spreadsheet*, prepared by K. Truesdell BAAQMD, and *Responses to BAAQMD 092310 E-mail Attachment 2*, prepared by Gregory Darvin Atmospheric Dynamics.

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

[33] *See* South Coast Air Quality Management District, Best Available Control Technology Guidelines, August 17, 2000, revised July 14, 2006, at 29; available at: www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power, Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005; BAAQMD Application No. 15487, Russell City Energy Center, Responses to Public Comments (Feb. 3, 2010), pp. 69-74; EPA Region 4, "National Combustion Turbine List," available at: www.epa.gov/region4/air/permits/national_ct_list.xls.

emissions limits of 9.45 pounds per turbine. Compliance with the CO permit limits will be demonstrated on a continuous basis using a continuous emissions monitor.

5.2.3 Best Available Control Technology for Precursor Organic Compounds (POC)

Emissions of POC from combustion sources are products of incomplete combustion, as is the case with CO emissions.

Control Technology Review:

Emissions control techniques for CO are also applicable to POC emissions from combustion sources and are discussed above. The appropriate BACT control device or technique for CO is therefore also the BACT control device or technique for POC.

Proposed BACT Control Technology for POC for Combined-Cycle Gas Turbines:

The District has reviewed the available control technologies in the BACT analysis for CO (equally applicable to POC) and determined that good combustion practice and abatement using an oxidation catalyst are the BACT technologies for controlling POC from the proposed combined-cycle gas turbines at Oakley Generating Station.

Proposed BACT Emissions Limit for POC for Combined-Cycle Gas Turbines:

To establish what level of emissions performance has been achieved in practice for this type of facility, the District reviewed the POC emissions limits of other large combined-cycle power plants using oxidation catalyst systems. The District reviewed BACT determinations for POC at the EPA RACT/BACT/LAER Clearinghouse, ARB BACT Clearinghouse and recent projects listed by the CEC as approved or under. The combined-cycle facilities with most stringent permit limits, as listed in these databases, are shown in the table below.

TABLE 11: POC EMISSION LIMITS FOR LARGE GAS TURBINES IN COMBINED-CYCLE POWER PLANTS

Facility Name	RBLC ID or CEC Docket #	VOC ppmvd @ 15% O2 (averaging period)
Wallula Power Plant	WA-0291	5.0 (1-hr)
Kleen Energy Systems, Inc.	CT-0151	5.0 (1-hr)
La Paz Generating Facility, GE option	AZ-0049	4.5 (3-hr)
Tracy Substatioin Expansion Project	NV-0035	4.0 (3-hr)
Duke Energy Arlington Valley	AZ-0043	4.0 (3-hr)
Copper Mountain Power	NV-0037	4.0 (3-hr) without duct firing; 1.9 (3-hr) with duct firing;
Wellton Mohawk Generating Station	AZ-0047	3.0 (3-hr)
Wellton Mohawk Generating Station	AZ-0047	3.0 (3-hr)
Ivanpah Energy Center, L.P.	NV-0038	2.3 (1-hr) without duct firing; 5.6 lb/hr with duct firing
La Paloma	1998-AFC-02	2.80 lb/hr and 0.7 (3-hr) (as propane)
Wansley Combined Cycle Energy Facility	GA-0102	2.0

Facility Name	RBLC ID or CEC Docket #	VOC ppmvd @ 15% O2 (averaging period)
Augusta Energy Center	GA-0093	2.0
McIntosh Combined Cycle Facility	GA-0105	2.0
Otay Mesa - Calpine	1999-AFC-05	2.0
Pastoria - Calpine	1999-AFC-07	2.0 (3-hr)
Elk Hills - Sempra & Oxy	1999-AFC-01	2.0 (3-hr)
Palomar Escondido - SDG&E	2001-AFC-24	2.0 (3-hr)
Magnolia - So. Ca. Power Producers	2001-AFC-06	2.0 (1-hr)
Avenal Energy - Avenal Power Center, LLC	2008-AFC-1	1.4 without duct firing; 2.0 with duct firing (3-hr)
Victorville Hybrid Gas-Solar - City of Victorville	2007-AFC-1	1.4 without duct firing; 2.0 with duct firing
Gila Bend Power Generating Station	AZ-0038	1.4
Sacramento Municipal Utility District	CA-0997	1.4
Cosumnes - SMUD	2001-AFC-19	1.4 (3-hr)
Lodi Energy Center - NCPA	2008-AFC-10	1.4 (3-hr)
Colusa II Generation Station - PG&E	2006-AFC-9	1.38 without; 2.0 with duct firing (1-hr)
FPL Turkey Point Power Plant	FL-0263	1.3 without duct firing; 1.9 with duct firing
Cogen Technologies Linden Venture, L.P.	NJ-0059	1.2
Empire Power Plant	NY-0100	1.0 without duct firing; 7.0 with duct firing
Sutter - Calpine	1997-AFC-02	1.0 (3-hr)
IDC Bellingham	CA-1050	1.0 (1-hr)
Blythe I - NextEra Energy (FPL)	1999-AFC-08	2.9 lb/hr (based on 1.0 ppm)
Russell City - Calpine & GE	2001-AFC-07	2.86 lb/hr (based on 1.0 ppm)
High Desert - Constellation	1997-AFC-01	2.51 lb/hr (based on 1.0 ppm)
CPV Warren [a]	VA-0291	0.7 without duct firing; 1.0 with duct firing; 1.4 with duct firing and power aug.
Warren County Facility, Scenario 1 [a]	VA-0308	0.7 without duct firing; 1.0 with duct firing; 1.4 with duct firing and power aug.
Warren County Facility, Scenario 2 [a]	VA-0308	0.7 without duct firing; 1.0 with duct firing
Warren County Facility, Scenario 3 [a]	VA-0308	0.7 without duct firing; 1.0 with duct firing

Notes:
Only facilities with known concentration limits were included for comparison.
[a] Warren County Facility and CPV Warren are the same facility (Permit Number 81391) and have not been built; a new application amended April 27, 2010, by Virginia Electric Power and Power Company (Dominion) will replace the listed determinations.

As this review of POC permit emissions limits for similar facilities shows, 1.0 ppmvd @ 15% O_2 is the most stringent emissions limit achieved by an emissions control device or technique on utility-sized gas turbines. As with CO, the CPV Warren plant has had a permit issued with certain limits lower than 1.0 ppm, but this plant has not been built (and will not be built, according to the permitting agency)[34] and so there is no operational data indicating this limit is achievable. Such a permit limit is not achieved-in-practice for purposes of the District's BACT requirement. The La Paloma facility has a 0.7 ppm limit, but it is measured at propane and it is based on a three-hour averaging period, both of which indicate that it is not a more stringent limit. The District's proposed limit here is 1.0 ppm measured as methane, which is approximately three times lighter than propane. As a result, the mass of POC emissions corresponding to a 0.7 ppm limit measured as propane will actually be over twice the mass of

[34] *See* e-mail from J. Pandey VADEQ to K. Truesdell BAAQMD dated July 7, 2010.

POC emissions corresponding to a 1.0 ppm limit measured as methane. This is reflected in the fact that the facility emits up to 2.8 pounds per hour of POC, whereas the proposed Oakley facility will only emit only 2.71 pounds per hour using larger turbines. (La Paloma uses ASEA Brown Boveri GT024 turbines with a capacity of 171.1 MW each, which are smaller than the Oakley facility's 213 MW GE Frame 7FA turbines.) In addition, the longer averaging time will allow for significant excursions above the 0.7 ppm permit limit compared with the District's proposed more stringent 1-hour averaging time. For all of these reasons, La Paloma does not establish that a limit has been achieved in practice that is more stringent than 1.0 ppm measured as methane and averaged over one hour.

To determine whether a lower limit could be justified as BACT 1 (technologically feasible and cost-effective), the District evaluated the costs and emissions reduction benefits of installing a larger oxidation catalyst that could be capable of consistently maintaining emissions below 0.7 ppm. Based on these analyses, the cost of achieving a 0.7 ppm permit limit would be an additional $77,882 per year (above what it would cost to achieve a 1.0 ppm limit), and the additional reduction in POC emissions would be approximately 3.29 tons per year, making an incremental cost-effectiveness value of $23,706 per ton of additional POC reduction. The total cost of achieving a 0.7 ppm POC limit (as opposed to the incremental costs of going from 1.0 ppm to 0.7 ppm) would be over $524,959 per year, and the total emission reductions from 1.4 ppm from the turbine to a 0.7 ppm limit would be 6.16 tons per year, resulting in a total (or "average") cost effectiveness value of $85,238. The District has adopted guidelines that limit the maximum cost per ton of POC controlled that would be considered cost-effective to $17,500.[35] Based on the high costs (on a per-ton basis) and the relatively little additional POC emissions benefit to be achieved (on a per-dollar basis), requiring a 0.7 ppm POC permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 0.7 ppm limit would be significantly more expensive, on a per-ton basis, than what the District would require any other similar facilities are required to achieve under the District's cost-effectiveness guidelines for POC.

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

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

5.2.4 Best Available Control Technology for Particulate Matter (PM) [36]

Particulate matter emissions from gas turbines result from several processes. Particulate matter may be entrained in the combustion air that passes through the combustor inlet filter, which 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. Sulfur in the natural gas can form PM during combustion, and can also combine with other compounds in the atmosphere after it is emitted to form secondary PM such as sulfates. Unburned hydrocarbons from the natural gas that are not fully combusted may condense to form PM.

Control Technology Review:

The District evaluated control technologies for PM in three areas: (1) pre-combustion controls (2) combustion controls, and (3) post-combustion controls.

Pre-Combustion Controls

- **Inlet Air Filter:** An inlet air filter is commonly used to protect the turbine from contaminants in the air, which can damage the turbine. There are two main types of filters, static filters and self-cleaning filters. Self-cleaning filters are cleaned periodically by a pulse of backflow air that dislodges the layer of dust collected on the outside surface of the filter. Self-cleaning filters require less maintenance than static filters and can be used in harsher environments. Both filter types can utilize high-efficiency filters capable of filtering particles less than 10 µm in diameter.

Combustion Controls

- **Good Combustion Practice:** Good combustion will ensure proper air/fuel mixing to achieve complete combustion, thus minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack.

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[36] This facility is subject to BACT requirements for PM_{10} only. $PM_{2.5}$, a subset of PM_{10}, is regulated under federal requirements in 40 C.F.R. Section 52.21 (PSD) and 40 C.F.R. Part 51, Appendix S (Non-Attainment NSR). The facility is not subject to PSD or $PM_{2.5}$ Non-Attainment NSR permit requirements under Section 52.21 or Appendix S because the facility is not a "major facility" for the purposes of these regulations. The District is therefore not conducting a PSD permitting analysis or an Appendix S permitting analysis for $PM_{2.5}$. For a detailed discussion of the applicability of these federal requirements for $PM_{2.5}$, see Section 7 below. The District notes, however, that for combustion turbines essentially all of the PM emissions are less than one micron in diameter, so it is both PM_{10} and $PM_{2.5}$. (*See* AP-42, Table 1.4-2, footnote c, 7/98 (available at www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf). Moreover, the same emissions control technologies that will be effective for PM_{10} for this facility will also be similarly effective for $PM_{2.5}$. The District's BACT analysis and emissions limit for PM_{10} will also therefore effectively be a BACT limit on $PM_{2.5}$ emissions as well, even though the facility is not subject to the federal $PM_{2.5}$ BACT requirements as discussed in Section 7.

- **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 PM during combustion. The use of low-sulfur natural gas is commercially available and demonstrated for gas turbines.

- **Dry Low-NO_x Combustor:** The use of a Dry Low-NO_x Combustor provides efficient combustion to ensure complete combustion thereby minimizing the emissions of unburned fuel that can form condensable PM. Dry Low-NO_x Combustors are in wide use on utility scale gas turbines.

<u>Post-Combustion Controls</u>

- **Electrostatic precipitators:** Electrostatic precipitators are used on solid fuel boilers and incinerators to remove PM 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 PM by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags that are periodically shaken to release the particulates into hoppers.

Inlet air filters, good combustion practice, clean-burning fuels, and Dry Low-NO_x Combustors are common control devices/techniques that are technically feasible for combined-cycle gas turbines and are often used to control emissions from sources of this type. These technologies are "achieved in practice" for this type of facility, and the District is proposing to require them here as the BACT control technologies.

With respect to the add-on controls – electrostatic precipitators and baghouses – these control devices are not achieved-in-practice for natural gas-fired gas turbines. These devices are normally used on solid-fuel fired sources or others with high PM emissions, and are not used in natural gas-fired applications, which have inherently low PM emissions. The District is not aware of any gas turbine that has ever been required to use add-on controls such as these. The District also reviewed the EPA BACT/LAER Clearinghouse and confirmed that EPA has no record of any post-combustion particulate controls that have been required for natural gas-fired gas turbines. The District has therefore determined that these control devices are not achieved in practice for purposes of the BACT analysis.

Furthermore, these devices would not be technologically feasible to implement here. If add-on control equipment were installed, it would create significant backpressure that would significantly reduce the efficiency of the plant and would cause more emissions per unit power produced. Moreover, these devices are designed to be applied to emissions streams with far higher particulate emissions, and they would have very little effect on the low-PM emissions streams from this facility in further reducing PM emissions.[37] It takes an emissions stream with a much higher grain loading for these types of abatement devices to operate efficiently. This low level of abatement efficiency (if any) also means that these types of control devices would not be cost-effective, even if they could feasibly be applied to this type of source. For all of these reasons, post-combustion particulate control equipment is not technologically feasible/cost effective for the proposed turbines.

Proposed BACT Control Technology for PM for Combined-Cycle Gas Turbines:

The District has determined that use of a high efficiency inlet air filter, low-sulfur natural gas and Dry Low-NO_x combustors with good combustion practice are the BACT control technologies for the proposed Oakley Generating Station. For low-sulfur fuel, the highest quality commercially available natural gas is natural gas that meets the PG&E Gas Rule 21, Section C standard of less than 1.0 grains of sulfur per 100 scf. This PG&E standard is the maximum sulfur content at any point in time. [38] The District is therefore proposing a BACT limit for fuel sulfur content of 1.0 grains of sulfur per 100 scf. Good combustion practice for the proposed gas turbines at Oakley Generating Station[39] would include the use of GE's DNL-2.6 combustion system, which controls turbine emissions of CO to 9 ppm (prior to abatement by the oxidation catalyst), Continuous Dynamics Monitoring (CDM) enhancements, including onsite visual tools for monitoring combustion dynamics and performing diagnostics, and other advanced controls software. The high level of control of CO indicates unburned hydrocarbons are also well controlled, thereby minimizing PM emissions. Compliance with the stringent CO emission limits will ensure that good combustion practice is being maintained.

The District is not proposing to impose a numerical emissions limit in addition to the BACT requirement to use low-sulfur natural gas and good combustion practices. The District's BACT regulations require the District to implement BACT either as a control device or technique (Regulation 2-2-206.1 and 2-2-206.3) or as an emission limitation (Regulation 2-2-206.2 and 2-2-206.4), and do not require both types of BACT limits. The District is therefore proposing the control techniques described above to fulfill the BACT requirement for PM in accordance with Regulations 2-2-206.1 and 2-2-206.3. The District considered whether to require a numerical

[37] For example, if a baghouse were installed on the turbines, the turbine exhaust at the *inlet* to the baghouse would contain less PM than is normally seen in baghouse *output*, after abatement. PM emissions from a baghouse are normally in the range 0.0013 to 0.01 grains per standard cubic foot (*see BAAQMD BACT/TBACT Workbook*, Section 11: Miscellaneous Sources), whereas PM emissions from the proposed Oakley Generating Station turbines would be 0.00095 gr/dscf (@ 15% O_2).

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

[39] *See* e-mail from J. McLucas, Radback Energy, to K. Truesdell dated 8/31/2010.

emissions limit as well, but has concluded that doing so would not be warranted here, given that there are no add-on control devices that the facility can use to control PM emissions. Assuming the facility is using good combustion practices, PM emissions will be determined by the amount of sulfur in the fuel and the way that the combustion equipment functions, which are factors that are not within the control of the operator. PM therefore presents a different situation than other pollutants such as NOx or CO where the project owner can design its add-on control systems to achieve the required level of emissions and ensure that it will comply with its emission limits by operating the add-on control systems properly.

This proposed BACT determination is consistent with guidance from the California Air Resources Board in setting BACT for natural gas-fired gas turbines.[40] This proposed BACT determination is also consistent with District BACT Guideline 89.1.6, which specifies BACT for PM_{10} for combined-cycle gas turbines with rated output of $\geq$ 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf.[41] These guidance documents do not suggest that a numerical emissions limit should be required as a BACT permit condition.

5.2.5 Best Available Control Technology for Sulfur Dioxide (SO_2)

Emissions of SO_2 are formed from the oxidation of trace amounts of sulfur in the fuel.

Control Technology Review:

There are two primary mechanisms used to reduce SO_2 emissions from combustion sources: (i) reduce the amount of sulfur in the fuel, and (ii) remove the sulfur from the combustion exhaust gases.

Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired power plants. Such plants in California are typically required to combust only natural gas with a sulfur content of less than 1 grain per 100 standard cubic feet (scf). In the Bay Area, PG&E supplies gas that complies with its Gas Rule 21, Section C, which requires a sulfur content of less than 1.0 grains of sulfur per 100 scf. This PG&E standard is the maximum sulfur content at any point in time. The requirement for low-sulfur natural gas is a control technique has been achieved in practice at other facilities, and it is technologically feasible and cost-effective. The District is therefore proposing to require the use of natural gas with a sulfur content of less than 1 grain/100 scf as a BACT control technique for SO_2.

Add-on controls that remove sulfur from the combustion exhaust, such as flue gas desulfurization, are not feasible for natural gas-fired power plants and have not been used at such

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[40] Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999, pg. 34.
[41] *See* Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm

facilities. These types of control devices are typically installed on coal fired power plants that burn fuels with much higher sulfur contents. There are two main types of SO_2 post-combustion control technologies: wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases and may remove up to 90% of the SO_2 from the exhaust stream. Dry scrubbers use an SO_2 sorbent injected as a powder or slurry to remove the SO_2 and the SO_2 and sorbent are removed by a particulate control device. The abatement efficiencies vary with different types of dry scrubbing technologies, but are generally lower than efficiencies for wet scrubbing technologies. These technologies are not feasible for combustion sources burning low sulfur content natural gas. The SO_x concentrations in the natural gas combustion exhaust gases are too low (less than 1 ppm) for the scrubbing technologies to work effectively or be technologically feasible and cost effective. These control technologies require much higher sulfur concentrations in the combustion exhaust gases to become feasible as a control technology. For this reason, they have not been used at natural gas-fired power plants such as the proposed Oakley Generating Station. As these control technologies have not been achieved in practice at other similar facilities and are not technologically feasible here, the District is not proposing to require them as BACT for this facility.

Proposed BACT Control Technology for SO_2 for Gas Turbines:

Fuel sulfur limits are the only feasible SO_2 control technology for natural gas combustion sources, and the District is proposing to require this technology as BACT. The District is proposing BACT permit limits requiring the use of natural gas containing a maximum of 1 grain of sulfur per 100 scf of natural gas. Compliance will be demonstrated with monthly sulfur content data. As with the PM BACT requirement, the District is proposing to implement BACT as a control technology only and not as a condition establishing a numerical limit on SO_2 emitted from the stack. The same reasons why the District has concluded that a numerical emissions limit would not be warranted for PM apply to as SO_2 well.

5.2.6 Best Available Control Technology For Startups, Shutdowns, and Combustor Tuning

Startup and shutdown periods are a normal part of the operation of natural gas-fired power plants. They involve emissions rates that are greater than emissions during steady-state operation and that 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 outside a certain temperature range, and so there may be partial or no abatement for NO_x, carbon monoxide and precursor organic compounds for a portion of the startup period. Thus, emissions can be minimized by reducing the duration of the startup sequence and by controlling the startup sequence to reduce emissions.

In addition, the gas turbines will need to perform 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 ensure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. Emissions will be greater during tuning because the turbines need to be operated at low load where they are less efficient, and because the SCR and oxidation catalyst may not be fully operational. The applicant will need to be able to conduct up to two 6-hour tuning operations per year per turbine.

Because emissions are greater during startups, shutdowns, and combustor tuning periods, the BACT limits established in the previous sections for steady-state operations are not technically feasible during these periods. The District is therefore establishing separate BACT limits representing the most stringent emissions limits that are achieved-in-practice or technologically feasible/cost-effective for this type of facility. To do so, the District has conducted an additional BACT analysis specifically for startups, shutdowns, and combustor tuning periods.

5.2.6.1 Turbine Startups and Shutdowns

Control Technology Review:

Best Work Practice: Emissions from startups and shutdowns can be minimized using best work practice. By following the plant equipment manufacturers' recommendations, power plant operators can minimize emissions during these operating modes and 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.

Fast-Start Technology: Turbine manufacturers have recently developed design improvements that allow combined-cycle facilities such as this one to start up more quickly and efficiently. These improvements allow combined-cycle facilities to bypass the steam turbine during the early stages of startup, eliminating some of the delay. With a conventional combined-cycle design, the combustion turbine must be held at low load while the steam turbine is being heated up, which needs to be done slowly to minimize thermal stresses and maintain the necessary clearances between the rotating and stationary components of the steam turbine. These new designs allow steam generated by the HRSGs to bypass the steam turbine during startups, allowing the turbines to come up to full load quickly. As the proper steam conditions are achieved, a portion of the steam will be sent to the steam turbine, which will ramp up slowly until the point is reached where steam is no longer bypassing the steam turbine. GE is marketing this new technology under the name "Rapid Response", and Siemens is marketing a similar technology under the name "Flex-Plant". The applicant is proposing to use the GE "Rapid Response" design for the Oakley Generating Station.

Proposed BACT Control Technology for Startups and Shutdowns

The District is proposing the use of best work practices with fast-start technology as BACT for startups and shutdowns of combined-cycle plants. Both control technologies are technically feasible and are the most effective technology available for decreasing startup and shutdown emissions. The applicant has proposed the use of best work practices and GE's Rapid Response Technology, which satisfies the BACT requirement. The facility will be equipped with a specially-designed HRSG that can heat up quickly without generating excessive thermal stresses. The facility will also be equipped with an auxiliary boiler that would provide auxiliary steam when the plant is offline and during startups. This auxiliary steam will be used for condensate sparging and to maintain the seals and prevent loss of vacuum in the steam turbine and condenser, so that the steam turbine is maintained in ready state and can start up as quickly as possible when called upon. (*See* Section 3.3 above for further detail regarding the use of the auxiliary boiler to improve startup performance.)

Proposed BACT Emissions Limits for Startups and Shutdowns

The District is also proposing numerical emissions limits for startups and shutdowns that represent the best emissions performance that can consistently be achieved by the BACT technology discussed above. The proposed emissions limits for Oakley Generating Station are shown in Table 12 below.

TABLE 12: PROPOSED STARTUP AND SHUTDOWN EMISSION LIMITS FOR OAKLEY GENERATING STATION

Pollutant	Cold Startup (lb/event)	Hot/Warm Startup (lb/event)	Shutdown Emission Limits (lb/event)
NO_x (as NO_2)	96.3	22.3	39.3
CO	360.2	85.2	140.2
POC (as CH_4)	67.1	31.1	17.1

The District is also proposing to add time limits for startups and shutdowns, in addition to numerical emissions limits. BACT limits are normally expressed as numerical emissions limits, as it is the actual emissions of air pollutants from a facility that have an impact on air quality. The numerical emissions limits are therefore the primary permit limits – and the permit conditions required by BACT – but the District is also proposing limits on startup and shutdown duration for this facility as an additional backstop to help ensure that startup and shutdown emissions are kept to a minimum. The District is proposing time limits of 30 minutes for hot/warm startups, 90 minutes for cold startups, and 30 minutes for shutdowns.

These proposed startup and shutdown limits are based on an analysis of what is involved in startup and shutdown operations using best work practices and GE's Rapid Response system.[42] The facility will typically start from a "ready-to-start" condition, with the electrical systems energized, steam process vessels filled to prestart level, manual valves in run position, and controls in auto. The plant will also typically have "Purge Credit" established, meaning the gas turbine and HRSG were purged with air to clear any remaining combustible gases and the gas turbine fuel train was prepared to assure that no fuel entered the gas turbine and HRSG while the unit was offline. The steps of purging the gases from the gas turbine and HRSG are also referred to as a "purge cycle" and, at conventional combined-cycle plants, are performed in the startup sequence and can take approximately 15 minutes. A purge cycle is required prior to firing the

[42] *See* Gordon R. Smith and Andrew Baxter, *GE Energy Rapid Response Combined Cycle*, PowerPoint presentation (Sept. 24, 2007).

gas turbine to prevent explosion of any residual gases. GE has worked with the National Fire Protection Agency to establish safe conditions without the delay in startup time that the purge cycle normally takes by moving the purge cycle to the end of the shutdown sequence. GE calls this feature Purge Credit.

The gas turbine starting process is initiated to roll the gas turbine, and the gas turbine is fired within a couple of minutes after roll. After fire, the gas turbine accelerates to full speed no load (FSNL) with the driving power provided by the load commutated inverter (LCI), a variable speed drive motoring the generator. At about 95% speed, the LCI disengages and the gas turbine settles at FSNL. Accelerating the gas turbines to 95% speed occurs as fuel is burned in certain burners within the combustors to ensure a stable flame and takes about 5 to 6 minutes to complete.[43] The combustors are not operating at their optimum efficiency at this point so emissions are higher than during steady-state operation.

On hot and warm starts,[44] the gas turbine synchronizes and loads directly to the desired load. This immediate loading is the benefit of the fast-start design compared to conventional combined-cycle designs, in which the combustion turbine cannot be brought up to minimum emissions compliance load until the steam turbine is brought up to operating temperature. Startup emissions in the Rapid Response plant are therefore lower than in a conventional combined-cycle plant, although they are still greater than steady-state emissions because the combustors must be loaded in a particular sequence to maintain a controlled and stable flame as load is increased. The combustors go through six modes of firing different burner combinations to reach steady-state emissions compliance, which takes another 5 or 6 minutes to complete. For cold starts, the gas turbine needs somewhat longer to come up to minimum emissions compliance load because the HRSG needs to be brought up to temperature gradually to reduce thermal stresses. Cold startups therefore require an additional hold at low load, which causes cold starts to be longer than hot and warm starts (although cold starts with the Rapid Response system are still shorter than cold starts with a conventional combined-cycle system).

Based on discussions with GE, the District estimates that with this Rapid-Response system, a typical hot/warm startup will take approximately 15 minutes until emissions reach compliance

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[43] See *Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines* GER3568g L.B. Davis and S.H Black, GE Power Systems, October 2000, at pp. 12-14. (available at: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3568g.pdf) See also *GE Rapid Response 207FA Plant Operation* G.R. Smith, GE June 4, 2010. See also Email from J. McLucas Radback Energy to K. Truesdell BAAQMD subject: OGS-Additional Information on Startups, dated 10/21/2010.

[44] Note that there will be no difference in performance between hot and warm startups. The District has often differentiated between hot startups and warm startups for other combined-cycle facilities with conventional designs (with hot startups being defined as startups when the turbine has been down for less than 8 hours and warm startups being defined as startups when the turbine has been down for 8-48 hours). To avoid confusion, the District is maintaining the hot/warm terminology here, even though there is no difference in startup performance between hot and warm startups. A hot/warm startups for this facility are defined as any startup that occurs within 48 hours of a shutdown.

with the proposed steady-state emission limits, and a typical cold startup will take approximately 46 minutes.[45] The District estimates that hot/warm startups will generate up to 22.3 pounds of NOx, 85.2 pounds of CO, and 31.1 pounds of POC; and that cold startups will generate up to 96.3 pounds of NOx, 360.2 pounds of CO, and 67.1 pounds of POC.[46] The District has found that the duration of turbine startups can vary significantly from startup to startup depending on a large number of variables, and that not-to-exceed startup limits need to reflect this variability so that the facility can comply with them consistently over the life of the facility under all reasonably foreseeable operating scenarios.[47] The District is therefore proposing limits on startup duration of 30 minutes for hot/warm startups and 90 minutes for cold startups, which is twice the duration of a typical startup as estimated by the equipment manufacturer, to ensure that the facility will be able to achieve these limits consistently.[48]

For shutdowns, the process is as follows. Over approximately 10 minutes, the gas turbines unload to the point where gas turbine exhaust temperature is slightly above rated steam temperature. This is the lowest load at which the gas turbine can operate without causing the steam temperature to drop below the rated steam temperature. The purpose of this hold is to avoid unintentionally cooling the steam turbine to a point that could cause the next plant startup to be longer than necessary. The gas turbine hold is expected to be around 20 percent load. While the gas turbines are holding, the steam turbine is unloaded by closing all steam turbine control valves. As the steam turbine control valves close, the steam turbine bypass valves begin to divert steam from the steam turbine to the condenser, essentially maintaining constant steam pressure. After approximately 5 minutes, the steam turbine will be completely unloaded, desynchronized, and the steam turbine will begin to decelerate. After the steam turbine has unloaded and the gas turbine resumes unloading, a second low load hold will occur when the gas

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[45] See Memorandum of Record of Telephone call dated 10/21/2010, prepared by K. Truesdell BAAQMD. GE provided estimates of what would be required to reach steady-state emissions compliance, but did not include any emissions at the steady-state emissions rate. The District's startup definitions provide that a startup ends with two consecutive compliant emissions readings, however. The District has therefore added one minute to GE's estimated startup duration and one minute's worth of steady-state emissions. Including one minute of steady-state emissions in addition to the manufacturer's emissions limits is appropriate to ensure compliance based on the CEMs' reading.

[46] See id.

[47] The District has evaluated startup data in prior permit proceedings for power plants such as this one and has documented the high degree of variability in individual startups. *See, e.g.*, Statement of Basis, Russell City Energy Center, Application No. 15487 (Dec. 8, 2008), available at www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2009/15487/B3161_nsr_15487_sb-corrected_121208.ashx, , at Section V.A.4.

[48] Since no fast-start facilities have yet been built, there is no startup data available from actual operating facilities on which to base a compliance margin specifically for the GE Rapid Response system. Variability in individual startups of twice the typical startup is not unusual for other combined-cycle facilities using conventional designs, however, and in the District's professional engineering judgment it is an appropriate basis for establishing a startup duration permit limit for a Rapid Response design.

turbine reaches approximately 10 percent load. This hold is designed to further reduce steam temperature and allow the cooler steam to reduce the temperature of the HRSG superheater lower header. Ten minutes are allotted for this hold per HRSG manufacturer direction. This hold is necessary to reduce the potential for HRSG damage during the purge operation shortly following shutdown, as described above, where relatively cool air will be blown through the gas turbine and HRSG as part of establishing Purge Credit. At the end of this hold, the gas turbines will resume ramping to zero load over a period of about 3 to 4 minutes whereupon they will desynchronize and begin fired shutdown. Flame is maintained in the gas turbines during deceleration to reduce the thermal shock on the hot gas path parts (gas turbine and HRSG). At about 20 percent gas turbine speed, fuel is cut off, the gas turbine flames out, and decelerates freely from this point to turning gear. Based on discussions with GE, the District estimates that shutdowns will take up to 30 minutes and involve 39.3 pounds of NOx emissions, 140.2 pounds of CO emissions, and 17.1 pounds of POC emissions.[49] The District is proposing these limits as not-to-exceed permit limits on shutdowns. The District does not believe any additional time allowance is required for shutdown.

The District has also compared these proposed startup and shutdown limits with other proposed facilities using fast-start combined cycle designs. The District compared the startup and shutdown limits for the Lodi Energy Center, which was licensed by the CEC in April of 2010,[50] and the Blythe II project, which is currently in the CEC licensing process.[51] Both of these projects incorporate the Siemens Flex-Plant 30 fast-start system. In addition, the District also evaluated the Victorville 2 Hybrid Power Project and the Palmdale Hybrid Power Project, which are designed with an earlier application of the fast-start concept. This application, which GE called "Rapid Start", provides for the steam turbine to be bypassed during startups to achieve faster starts and is therefore somewhat comparable, although it does not include all of the additional elements of the more recent Rapid Response design. In comparing these facilities, the District looked at the permit limits applicable to startups and shutdowns combined, for several reasons. One reason is that every startup is necessarily coupled with a shutdown, as by definition a startup has to follow a shutdown. Another reason is that the proposed Oakley project will incorporate "Purge Credit" into its shutdown sequence, which removes a required step from the startup process as described above so that the facility can be started up more quickly. It would not make sense to penalize this project for moving this step from the startup sequence to the shutdown sequence, and so to avoid such an outcome the District evaluated overall facility performance for startups and shutdowns combined. The comparison of the applicable permit conditions for these facilities and the proposed Oakley Generating Station permit conditions is summarized in Table 13 below.

[49] See Memorandum of Record of Telephone call dated 10/21/2010, prepared by K. Truesdell BAAQMD. As with the startup emissions, the manufacturer's shutdown emissions do not account for any time at steady-state. The District therefore add one minute's worth of steady-state emissions to the manufacturer's estimates to establish permit limits on turbine shutdowns.
[50] *See* Final Commission Decision, available at: www.energy.ca.gov/2010publications/CEC-800-2010-003/CEC-800-2010-003-CMF.PDF .
[51] The Energy Commission's web page for this proceeding can be found at www.energy.ca.gov/sitingcases/blythe2/compliance/ .

TABLE 13: STARTUP AND SHUTDOWN PERMIT LIMITS FOR SIMILAR COMBINED-CYCLE POWER PLANT PROEJCTS USING FAST-START TECHNOLOGY

Facility Name	Victorville 2 Hybrid Power Project	Palmdale Hybrid Power Project	Lodi Energy Center	Blythe Energy Project II (proposed)	Oakley Generating Station (proposed)
Technology	GE Rapid Start Process	GE Rapid Start Process	Siemens Flex-Plant 30	Siemens Flex-Plant 30	GE Rapid Response
Maximum Heat Input (MMBtu/hr/gas turbine)	1736.4	1736.4	2142	2019.6	2150
Hot/Warm Startup + Shutdown					
Total Duration (min)	110	110	360	120	60
Total Emissions Limit (lb)					
NOx	97	97	960	111.6	61
CO	666	666	5400	83.8	225
POC	no limit	no limit	96	no limit	48
Cold Startup + Shutdown					
Total Duration (min)	140	140	360	240	120
Total Emissions Limit (lb)					
NOx	153	153	960	150.6	135
CO	747	747	5400	165.7	500
POC	no limit	no limit	96	no limit	84

As Table 13 shows, the proposed permit conditions for the Oakley Generating Station are very stringent compared with other similar facilities, and meet or exceed all of the other facilities' permit limits with one exception. The one exception is the CO emissions limits that are currently being proposed for the Blythe II project, which, if adopted in their current form, will limit combined CO emissions to 83.8 pounds of CO for a hot/warm startup and shutdown (compared with the proposed 225 pounds for Oakley) and 165.7 pounds of CO for a cold startup and shutdown (compared with the proposed 500 pounds for Oakley). The District has evaluated these proposed CO limits for Blythe II and has concluded that they do not suggest that the District's proposed limits for the Oakley Generating Station are inappropriate, for several reasons. First, the Blythe II project is still under review, and the limits that are currently being considered have not yet been finalized and could potentially change when the project is approved. Second, even if the Blythe II project is ultimately permitted with these limits, the facility is not yet built and operational and so there is no actual operating data that demonstrate that these limits will in fact be achievable by the facility. And third, even assuming that the

Blythe II facility will be able to be operated in compliance these proposed permit conditions, the limits being proposed for the facility reflect a balance between NOx and CO reductions that has been made in a manner different from how the District would make it. There is an inherent tradeoff between achieving additional NOx reductions and achieving additional CO reductions because NOx is reduced by lowering the combustion temperature to reduce the formation of thermal NOx whereas CO is reduced by increasing the combustion temperature to avoid incomplete combustion. (*See* discussion in Section 5.2.1 above for more details.) The District prioritizes NOx reductions over CO reductions because the Bay Area is not in attainment of the state and federal ambient air quality standards for ozone (NOx is a precursor to ozone formation), whereas it is in attainment of the CO standards. The District therefore prefers lower NOx limits even if that means somewhat higher CO limits. In this case, the Oakley Generating Station will be able to achieve NOx emissions for startups that are significantly below the proposed limits for Blythe II (61 pounds vs. 111.6 pounds for hot/warm startups/shutdowns, and 135 pounds vs. 150.6 pounds for cold startups/shutdowns). The District considers these additional NOx reductions to be more important than the additional CO reductions reflected in the proposed Blythe II conditions. For all of these reasons, the District has concluded that the Blythe II project does not suggest that the proposed conditions for the Oakley Generating Station are inappropriate.

Based on all of this analysis, the District is proposing the startup and shutdown conditions described above as BACT for the Oakley Generating Station. The District finds that these are the most stringent emission limits that can be achieved by this facility based on all of the information available at this time regarding the performance of this newly developed technology.

5.2.6.2 Combustor Tuning

Combustor tuning is required to maintain the gas turbines in optimal operating condition. Tuning is done in response to turbine wear and variations in fuel, temperature, and humidity. The gas turbines will be subject to extremely stringent limits for startups and shutdowns in addition to stringent steady-state limits, so providing an allowance for tuning is necessary to assure compliance during the rest of the year.

The burners in the turbines that would be used at the Oakley Generating Station have 6 modes of operation, depending on where and how much fuel and air are routed to different parts of the burner (combustion fuel staging). Details on the modes of operation can be seen in the GE Publication #GER 3568G "Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines." Tuning involves testing and adjusting the 6 modes and the transition from one mode to another. These operations are time-intensive and are expected to take up to 6 hours to complete. The reason that up to 6 hours are required to complete the tuning is that during tuning, the turbine operating rate is brought up 5 MW at a time and tuning is performed at each MW level. The turbines are held at each load level while settings are varied to establish the optimal operating conditions. Tuning would need to be performed up to two times per year per turbine. Each turbine would be able to be tuned separately to keep tuning emissions to a minimum.

Tuning has traditionally been performed during cold startups. Cold startups involve bringing the turbine load up slowly, and so they provide an appropriate opportunity to conduct tuning.

Recently, regulatory agencies have started imposing shorter time limits on cold startups, and so it has become increasingly difficult for operators to complete tuning within their cold startup time limits. Recent permits have therefore had to include specific provisions allowing for tuning operations outside of cold startups. Since tuning operations were originally conducted under cold startup limits, these provisions have typically provided for tuning operations to be subject to the same emissions limits applicable during cold startups. These limits are also generally appropriate for tuning because tuning involves low-load operation where emissions controls are not as effective, as is the case with cold startups. (Tuning takes longer than cold startups, however, because the turbines must be kept at each load level for a period of time while tuning takes place, and cannot be ramped up as soon as equipment conditions allow.)

The District is therefore proposing that tuning operations should be subject to emissions limits at least as stringent as the hourly emissions limits that apply during cold startups – 96 lb/hour of NOx, 260 lb/hour of CO, and 67 lb/hour of POC. The District believes that it may be possible to maintain tuning emissions at even lower levels, although the facility has not yet been built and so there is not yet sufficient operating data on which to base lower permit limits. The District is therefore proposing that further emissions limits for tuning operations would be established after the facility is built based on test data obtained during actual tuning operations. These further emissions limits would be at least as stringent as the cold startup limits, and would be even lower if lower limits prove to be feasible.

The District is therefore proposing a provision that would allow the Oakley Generating Station to conduct up to two tuning events per year per turbine, with a duration not to exceed 6 hours per tuning event. In addition, the facility would be allowed to conduct tuning on only one turbine at a time. Emissions would be subject to the lowest limits that can be achieved by the facility, which the District would establish based on testing after the facility is built and which would in no event be greater than the hourly emissions rates applicable for cold startups.

5.2.7 <u>Best Available Control Technology During Gas Turbine Commissioning</u>

The combined-cycle gas turbines and associated equipment are highly complex and have 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 gas turbine generators needs to be fine-tuned at zero load, partial load, and full load to optimize its performance. The dry-low NO_x combustors also need to be tuned to ensure that the turbines run efficiently while meeting both the performance guarantees and emission guarantees. In addition, the selective catalytic reduction (SCR) systems and oxidation catalysts need to be installed and tuned.

The combined-cycle gas turbines 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 BACT for this phase of the facility's operation. Alternate BACT limits must therefore be specified for this mode of operation. To do so, the District has conducted an additional 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.

To implement best work practices as an enforceable BACT requirement, the District is proposing conditions that will require the turbines to minimize emissions to the maximum extent possible during commissioning. The District is also proposing numerical emissions limits based upon the equipment manufacturer's best estimates of uncontrolled emissions at the operating loads that the turbines will experience during commissioning (see table below).[52] The proposed permit conditions will limit emissions to below the following levels:

TABLE 14: COMMISSIONING PERIOD EMISSION LIMITS

Air Pollutant	Proposed Commissioning Period Emission Limits (Uncontrolled or Partially controlled)	
	(lb/calendar day)	**(lb/hr)**
NO_2	2,380.8	148.7
Carbon Monoxide	13,303	700

Note: Please see "OGS Supplemental Air Quality Filing April 7 2010" Table 5.1A-5b for GE's detailed commissioning schedule.

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 District is also proposing permit conditions to minimize the duration of commissioning activities. The proposed conditions require the facility to tune the gas turbines 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 District is also proposing to cap

[52] *See* e-mail attachment from Greg Darvin, Atmospheric Dynamics, to K. Truesdell, BAAQMD, dated 7/19/2010

the total amount of time that the turbines can operate partially abated and/or without the SCR systems and oxidation catalysts at 831 total 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 limit is based on the following estimates from GE of the time it will take for each specific commissioning activity in Table 15.

TABLE 15: COMMISSIONING SCHEDULE FOR OAKLEY GENERATING STATION

Test Description	Duration (hours)	Average GT Load (%)	Total Emissions (tons)			
			NO_X	CO	VOC	PM_{10}
GT Initial Start-up GT first firing GT FSNL on primary fuel & generator filtration GT intertriping matrix checks GT generator short circuit, overspeed and open circuit tests	50	0	1.5	11.4	1.0	0.2
GT Sync & Load GT first synchro	10	7.5	0.7	3.5	0.2	0.0
HRSG Steam blows HRSG MS steam blows HRSG CRH & HRH steam blows HRSG LP steam blows Air cooled condenser flushing Steam to gland seal, condenser vacuum tests	240	7.5	5.7	13.8	4.3	1.1
HRSG Operation on Steam Bypass HRSG startup, steam bypass checks HRSG steam safety valve tests HRSG & BOP control loop tuning	323	25	16	9.7	0.6	1.5
GT Loading up to Base on PPM Part load tests Full load tests HRSG operation on bypass for steam purity	50	46	2.5	1.5	0.1	0.2
ST Initial Start-up ST generator filtration ST intertriping checks ST generator short circuit, overspeed and open circuit tests	23	19	1.1	0.7	0.0	0.1
ST Sync & Load ST first synchro ST tests on load with one GT	38	68	0.3	0.1	0.0	0.2
GT Tuning up to Base on PSS Mode with Primary Fuel Part load tests Full load tests	97	64	0.7	0.2	0.1	0.4
Total[a]	831	-	28.6	40.8	6.4	3.7

See "OGS Supplemental Air Quality Filing April 7 2010" Table 5.1A-5b for GE's detailed commissioning schedule. Totals are slightly different than adding the emissions for each activity due to rounding. Emissions will be limited by annual permit limits.

The District also looked to other similar facilities to determine whether any other facility has achieved better commissioning performance. Commissioning limits for conventional combined-cycle plants would not be feasible for this facility due to the complex design of Rapid Response that allows faster startups, and there are currently no operating GE Rapid Response or Siemens Flex Plant 30 plants with which to compare the proposed commissioning period. The proposed Siemens Flex Plant 30 in Lodi, CA is for one gas turbine and one steam turbine and does not have a permit limit for commissioning hours.[53] The Victorville 2 Hybrid Power Project and City of Palmdale Hybrid Power Plant Project will both use GE's Rapid Start Process, which utilizes a modified HRSG and an auxiliary boiler to reduce startup times, and they are limited to 624 hours of commissioning per turbine.[54] The proposed Siemens Flex Plant 30 for Blythe Energy Project Phase II Amendment, which is proposed as two gas turbines and one steam turbine, is proposed for up to 734 hours of commissioning per gas turbine/HRSG train.[55] The BACT limit for the commissioning period of conventional combined-cycle plants is not technologically feasible for the combined-cycle plant proposed for Oakley Generating Station due to the complex design of Rapid Response that allows faster startups. The proposed limit for the commissioning period for Oakley Generating Station is less than the limits proposed at other fast start/rapid start plants proposed in California. The District is proposing 831 total hours for the BACT limit on commissioning at Oakley Generating Station.

Emissions during commissioning will accrue towards the facility's annual emission limits. 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 District for review and approval.

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[53] See Lodi Energy Center Final Commission Decision (08-AFC-10), California Energy Commission, April 2010. (available at: http://www.energy.ca.gov/sitingcases/lodi/documents/index.html)

[54] See Victorville 2 Hybrid Power Project Final Commission Decision, California Energy Commission, July 2008, AQT-23 at p. 131. (available at: http://www.energy.ca.gov/sitingcases/victorville2/documents/index.html). See also VOLUME 2: Preliminary Staff Assessment for the Palmdale Hybrid Power Plant Project (Docket # 08-AFC-9), February 2010, AQT-23 at p. 4.1-65 (available at: http://www.energy.ca.gov/sitingcases/palmdale/documents/index.html)

[55] *See* Final Determination of Compliance Blythe Energy Project II, Mojave Desert Air Quality Management District, August 10, 2010, at p. 25.

5.3 Fire Pump Diesel Engine

The proposed Oakley Generating Station will require an emergency fire pump diesel engine to be used in case of emergency to provide water to fight fires. The fire pump diesel 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 National Fire Protection Agency (NFPA) to ensure reliability in case of fire.

The following section provides the District's BACT analysis for the project's fire pump diesel engine. The diesel fire pump engine will have the potential to emit over 10 pounds per day of NOx and CO since emergency use is not limited, and it is subject to BACT for these pollutants.

Control Technology Review:

The 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

The use of diesel fuel that meets the CARB ultra-low sulfur diesel fuel standard (< 0.0015% by weight sulfur) can reduce the amount of NO_x formed during combustion. Using ultra-low sulfur fuel reduces NO_x 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_x during combustion. Ultra-low sulfur diesel fuel is available and demonstrated for stationary compression ignition engines. It is technically feasible for the fire pump engine.[56]

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_x and Carbon Monoxide. These features include turbocharging, which uses an exhaust gas-driven air compressor to increase the mass of air entering the engine to create more power and thereby increase efficiency; intercooling, or charge air cooling, which uses an air-to-air or air-to-liquid heat exchange device to increase the intake air charge density through cooling, another method to increase efficiency; retarded injection timing, which slightly delays the injection of fuel into the engine to reduce the peak flame temperature, thereby improving NO_x emissions (but typically resulting in higher PM emissions); exhaust gas recirculation, which allows a controlled portion of spent combustion gases to circulate back into the intake system where they mix with pre-

[56] Under Title 17, California Code of Regulations, section 93115 "Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines," the emergency fire pump engine will use only California ultra-low sulfur Diesel fuel when operating.

combustion air, similarly reducing peak combustion temperature; and the use of a pre-combustion chamber, which involves a prechamber in the engine that improves air/fuel mixing and lowers combustion temperature.

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. Emissions from such engines are regulated by EPA under a system of "Tiers", or progressively more stringent emissions standards that engine manufacturers must meet. Engine manufacturers design their equipment using appropriate control technology to meet these EPA-designated Tiers. Diesel engine users, such as the Oakley Generating Station 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 types of engines are commercially available to be purchased for this project, and what "Tier" standards such equipment can meet. The technologies that are commercially available are those that manufacturers are using to achieve the EPA "Tier 3" requirements for engines of the class needed for emergency fire service at the Oakley Generating Station.

Post-Combustion Controls

Finally, there are several post-combustion technologies that could potentially be used to remove emissions from the fire pump diesel engine's exhaust before they are emitted to the atmosphere. One such system discussed above in connection with the gas turbines and auxiliary boiler is **s**elective catalytic reduction (SCR), which uses a reagent, typically ammonia or urea, to convert NOx to nitrogen and oxygen over a catalyst. Another after-treatment based NO_x control technology is referred to as the lean-NO_x catalyst. Similar in principle to an SCR system, a Lean-NO_x Catalyst system relies on injection of a reagent upstream of the catalyst to reduce NO_x emissions. Finally, NO_x adsorbers, also called NO_x traps, are one of the newest emission control strategies under development. They employ catalysts that adsorb NO_x in the exhaust stream when the engine runs lean. After the adsorber has been fully saturated with NO_x, the system is regenerated with released NO_x being catalytically reduced when the engine runs rich.

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 Oakley Generating Station, however. 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 will also compromise reliability, performance, and safe operation of the fire pump.[57]

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 Oakley Generating Station are designed differently than other stationary or offroad diesel-fueled engines. Direct-drive fire pump engines must meet the stringent National Fire Protection Association (NFPA) standards that establish minimum requirements for reserve

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

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).[58] Adding exhaust system controls to these engines would void the existing certifications.[59]

Proposed BACT Control Technology Emergency Fire Pump Diesel Engines

The District has determined the use of ultra-low sulfur diesel and Tier 3 engine technology are the only feasible control technologies and therefore meet BACT. Tier 3 engines incorporate control technologies that meet the emission standards for fire pump diesel engines required by EPA in 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.[60] EPA does not require future stationary fire pump engines to meet Tier 4 emission standards, which would likely involve the use of after-treatment devices. The proposed Tier 3 engine also meets the emission standards set forth in the California Air Resources Board (CARB) Airborne Toxic Control Measure for Stationary Compression Ignition Engines (sections 93115 through 93115.15, title 17, California Code of Regulations).

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[58] 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 prohibitive.

[59] 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.

[60] 40 CFR Part 60, Subpart IIII, Table 4 - Emission Standards for Stationary Fire Pump Engines

6. Requirement to Offset Emissions Increases

District regulations require that new facilities must provide Emission Reduction Credits (ERCs) to offset the increases in air emissions that they will cause. ERCs are generated when old facilities sources are shut down, or when sources are controlled below regulatory limits. The emissions reductions granted by the District are used to offset the increases from new facilities, so that there will be no overall increase in emissions from facilities subject to this offset program.

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x emission increases from permitted sources at facilities that will emit 10 tons per year or more of those pollutants. For facilities that will emit more than 35 tons per year of NO_x 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. For PM_{10} and SO_2, offsets are required for facilities that will emit 100 tons per year or more of those pollutants under District Regulation 2-2-303.

Pursuant to District Regulation 2-2-302, ERCs must be surrendered by the time the District issues the Authority to Construct for the facility, although many applicants identify the ERCs they hold during the permitting process in order to demonstrate that they will be able to satisfy the emission offset requirements. At the time of issuance of this Preliminary Determination of Compliance, the applicant has not identified which emission reduction credits will be used to offset emissions from this project. The applicant has committed to identify a list of offsets holders who have indicated in writing their willingness to sell sufficient ERCs to offset the levels of POC and NO_x emissions specified below prior to issuance of the Final Determination of Compliance. Pursuant to District Regulation 2-2-302, the applicant will be required to surrender sufficient ERCs to offset the levels of POC and NO_x emissions specified below prior to issuance of the Authority to Construct.

The District's analysis of the applicable offset requirements for the four pollutants for which offsets requirements have been established is outlined below.

6.1 POC Offsets

Because the proposed Oakley Generating Station will emit less than 35 tons of POC per year from permitted sources, the POC emissions must be offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302. The facility will be required to provide offsets for 29.49 tons per year of POC emissions.

6.2 NO_x Offsets

Because the proposed Oakley Generating Station will emit greater than 35 tons per year of NO_x from permitted sources, the NO_x emissions must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. The facility will emit up to 98.78 tons/yr of NO_x, and will therefore be required to provide offsets for 113.60 tons per year of NO_x emissions.

6.3 PM_{10} Offsets

Because the total PM_{10} emissions from permitted sources will not exceed 100 tons per year, the proposed Oakley Generating Station is not required to offset its PM_{10} emissions under District Regulation 2-2-303.

6.4 SO_2 Offsets

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

7. Federal Permit Requirements

In addition to the Bay Area Air Quality Management District permit requirements in District Regulation 2, Rule 2 and Regulation 2, Rule 3, there are two federal permitting programs that apply to major facilities: (i) the federal "Prevention of Significant Deterioration" (PSD) requirements under 40 C.F.R. section 52.21; and (ii) the "Non-Attainment New Source Review" (Non-Attainment NSR) requirements for $PM_{2.5}$ sources set forth in Appendix S of 40 C.F.R. Part 51. The District has analyzed these requirements for the proposed Oakley Generating Station and has determined that neither of these permit requirements applies to this facility because it will not be a major source under either of those programs. The District is therefore not proposing to issue a PSD permit for this facility or to include Appendix S $PM_{2.5}$ Non-Attainment NSR requirements in the permit.

7.1 Federal "Prevention of Significant Deterioration" Program

The federal PSD program applies to "major" stationary sources. For 28 categories, including fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input such as the proposed Oakley Generating Station, major stationary source means a new source that emits more than 100 tons per year of any PSD pollutant.[61] PSD pollutants are regulated pollutants for which the Bay Area is not in violation of the National Ambient Air Quality Standard (NAAQS) for that pollutant. For the Bay Area, PSD pollutants include carbon monoxide, PM_{10}, $PM_{2.5}$, and SO_2, among others. Facilities that exceed the federal PSD "major source" threshold for any of these pollutants must apply for and obtain PSD permits before they can commence construction. Although PSD permits are federal permits issued under the authority of EPA Region 9, the District conducts the PSD analysis and issues PSD permits on behalf of EPA Region 9 pursuant to a Delegation Agreement between the District and EPA Region 9.[62]

The Oakley Generating Station will not be subject to PSD permitting requirements because it is not a "major source" because annual emissions are less than 100 tons of all PSD pollutants. (*See* Annual Emissions, listed in Table 7 in Section 4.1.6 above.) Annual emissions will be subject to enforceable permit limits to ensure that they remain below the amounts listed in Table 7. As explained in Section 4.1.6, although these annual emissions rates are based on certain assumptions about how the facility will operate, they will subject to enforceable permit conditions that will ensure that emissions do not exceed the 100 ton PSD threshold. The facility will be required to monitor its emissions and ensure that they do not exceed the limits during any

[61] Note that starting in 2011, EPA will regulate greenhouse gas emissions under the PSD program, with a "major source" applicability threshold of 100,000 tons per year and a PSD "significance" threshold 75,000 tons per year. *See* 40 C.F.R. § 52.21(b)(1)(i)(a) and § 52.21(b)(49)(iv)-(v). For new sources such as this one that are not otherwise subject to PSD permitting requirements, these requirements would not be effective until July 1, 2011.

[62] The District also has incorporated PSD requirements from the federal PSD regulations into its NSR Rule in Regulation 2, Rule 2. The substance of these requirements in Regulation 2, Rule 2 track the federal requirements.

12-month period. If it appears that the facility is nearing its annual limit, it will be required by law to reduce or curtail operations to ensure that emissions do not exceed the permitting annual rates. These permit limits will ensure that the facility does not operate in a manner that would require a PSD permit. EPA's PSD program specifically allows the use of enforceable emissions limitations in the permit as a basis for concluding that a facility's emissions will not trigger PSD requirements and that the facility is therefore not subject to PSD permitting.[63] The District is therefore not proposing to issue a federal PSD permit for this facility.

7.2 Non-Attainment NSR for $PM_{2.5}$

The Bay Area has recently been designated as "non-attainment" of the National Ambient Air Quality Standard for $PM_{2.5}$ (24-hour average).[64] Areas classified as non-attainment are subject to the "Non-Attainment New Source Review" (Non-Attainment NSR) requirements of the federal Clean Air Act. The Clean Air Act requires states to develop Non-Attainment NSR regulations to implement this requirement within 3 years of a non-attainment designation, and the District will be doing so for $PM_{2.5}$ in the months and years to come. In the interim, while the District is working on its own $PM_{2.5}$ Non-Attainment NSR regulations, Non-Attainment NSR for $PM_{2.5}$ is governed by the federal Non-Attainment NSR rule in EPA's Emissions Offset Interpretive Ruling, which is set forth in Appendix S of 40 C.F.R. Part 51 ("Appendix S").

Non-Attainment NSR under Appendix S is a federal permit program and is implemented under the federal regulations set forth in Appendix S. It is not a state law permitting program and it is not implemented under the requirements of District regulations established pursuant to the California Health & Safety Code. The Environmental Protection Agency has determined that the District can impose conditions in its District permits (Authority to Construct and Permit to Operate) that will allow a facility to establish compliance with the federal Non-Attainment NSR requirements for $PM_{2.5}$.[65,66] If the District includes requirements in its District permits pursuant to District Regulation 2-1-403 (Permit Conditions) that satisfy the applicable $PM_{2.5}$ Non-

[63] See 40 C.F.R. § 52.21(b)(6); *see also National Mining Ass'n v. EPA*, 50 F.3d 1351, 1365 (D.C. Cir. 1995).

[64] EPA promulgated National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ in 1997 (with an update in 2006), and began designating certain regions of the country as non-attainment with those Standards starting in 2005. EPA made a determination as to the region's attainment status with respect to $PM_{2.5}$, which it published on November 13, 2009. EPA determined that the Bay Area is in attainment of the $PM_{2.5}$ NAAQS for the annual standard, and is non-attainment for the 24-hour standard. The EPA's non-attainment determination for the $PM_{2.5}$ 24-hour standard became effective on December 14, 2009 (See Federal Register Friday November 13, 2009, Air Quality Designations for the 2006 24-Hour Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards).

[65] Letter dated 10/28/09 from Jack Broadbent of BAAQMD to Deborah Jordan U.S. EPA Region IX, Re: Guidance on "Appendix S" Non-Attainment NSR Permitting for $PM_{2.5}$ Source During $PM_{2.5}$ Transition Period.

[66] Letter dated 12/9/09 from Deborah Jordan U.S. EPA Region IX to Jack Broadbent of BAAQMD, Re: Guidance on "Appendix S" Non-Attainment NSR Permitting for $PM_{2.5}$ Source During $PM_{2.5}$ Transition Period.

Attainment NSR requirements of Appendix S for a source, EPA has determined that it will treat those conditions as satisfying the federal Appendix S requirements for that source.

Under Appendix S, Non-Attainment NSR requirements for $PM_{2.5}$ apply to facilities with $PM_{2.5}$ emissions of more than 100 tons per year. (*See* 40 CFR 51, Appendix S, II.A.4(i)(a) establishing 100 tpy threshold for regulation of Major Stationary Sources.[67]) The proposed Oakley Generating Station would emit only 63.88 tons per year of $PM_{2.5}$, so the Appendix S Non-Attainment NSR requirements do not apply for this facility. The District is therefore not proposing to include conditions in the permit for compliance with Appendix S for $PM_{2.5}$. Note, however, that the proposed permit includes permit limits on PM_{10}, which will be effective to control $PM_{2.5}$ emissions as well.

[67] The facility will emit less than 100 tons per year of direct $PM_{2.5}$ emissions and less than 100 tons per year of any $PM_{2.5}$ precursors, as defined in Appendix S II.A.31(iii). (*See* Preliminary Determination of Compliance, Table 7.)

8. Health Risk Screening Analyses

Pursuant to the District's Toxic Risk Management regulation (Regulation 2, Rule 5), 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 proposed Oakley Generation Station. In accordance with the requirements of District Regulation 2, Rule 5 and California Office of Health Hazard Assessment (OEHHA) guidelines, the impact on public health due to the emission of these compounds was assessed utilizing EPA-approved air pollutant dispersion models.

Tables 16 and 17 present the Health Risk Assessment results for the Oakley Generating Station. Table 16 summarizes the maximum cancer and non-cancer health risks from the project as a whole, and Table 17 summarizes the maximum cancer risk from each source individually.

TABLE 16: HEALTH RISK ASSESSMENT RESULTS FOR THE PROJECT

Receptor	Cancer Risk	Chronic Non-Cancer Hazard Index	Acute Non-Cancer Hazard Index
Maximum Values	1.56 in a million	0.0832	0.2665

TABLE 17: HEALTH RISK ASSESSMENT RESULTS FROM EACH SOURCE

Source	Maximum Residential/Worker Cancer Risk from Source
North Gas Turbine	0.70 in a million
South Gas Turbine	0.65 in a million
Auxiliary Boiler	0.03 in a million
Evaporative Fluid Cooler	0.39 in a million
Fire Pump Diesel Engine	0.73 in a million

The District performed a health risk assessment 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). Based on this assessment, the proposed sources for Oakley Generating Station will comply with the project risk requirements in accordance with the District's Regulation 2, Rule 5. Regulation 2, Rule 5 requires that the maximum health risk from the project as a whole must be less than 10 in one million excess cancer risk and less than a hazard index of 1.0 chronic and acute non-cancer risk; and that the maximum health risk from each individual source at the project must be less than 1.0 in one million excess cancer risk and less than a hazard index of 0.2 chronic non-cancer risk. As shown in Table 16, the maximum increased carcinogenic risk attributed to this project is 1.56 in one million, and the chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants are 0.0832 and 0.2665, respectively. As shown in Table 17, the risk from each source individually is below 1.0 in a million maximum individual cancer risk; and since the maximum chronic non-cancer hazard index for the project as a whole is less than 0.2, the chronic hazard index for each source is less than 0.20. Please see Appendix B (Memo dated August 12, 2010, prepared by Glen Long, Air Toxics Section) for further discussion.

9. Other Applicable Requirements

The following section summarizes the applicable District, state and federal rules and regulations and describes how the Oakley Generating Station will comply with those requirements.

9.1 Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's 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.

Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Sections 2-1-301 and 2-1-302, the applicant has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for all regulated sources at the proposed Oakley Generating Station. Those permits will be issued after the CEC completes its licensing process.

Regulation 2, Rule 2: New Source Review

The primary requirements of New Source Review that apply to the proposed Oakley Generating Station are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", Section 2-2-303, "Offset Requirement, PM_{10} and Sulfur Dioxide, NSR".

Regulation 2, Rule 2, Section 301: BACT

The District has performed a BACT analysis for the gas turbines, auxiliary boiler, and fire pump diesel engine as shown in Section 5. The proposed Oakley Generating Station meets the BACT requirements under Section 2-2-301.

Regulation 2, Rule 2: Sections 302 and 303

The District has presented the offsets required for the project for NO_x and POC as shown in Section 6 of this document. The proposed Oakley Generating Station will meet the offset requirements under Sections 2-2-302 and 2-2-303.

Regulation 2, Rule 2: Sections 304, 305, 306 and 414

The Prevention of Significant Deterioration (PSD) requirements in District Regulation 2, Rule 2 (Sections 304, 305, 306, and 308) are intended to implement the federal PSD requirements in 40 C.F.R. Section 52.21 and track those federal requirements. The proposed Oakley Generating Station will not be subject to PSD requirements. Those requirements are discussed in detail in Section 7 above.

Regulation 2, Rule 3: Power Plants

Pursuant to Section 2-3-304, this Preliminary Determination of Compliance is subject to the public notice, public comment, and public inspection requirements contained in Sections 2-2-406 and 2-2-407. This document presents the Preliminary Determination of Compliance for the project. The District will consider all comments received during the comment period prior to issuing any Final Determination of Compliance for the project. The Final Determination of Compliance will be relied upon by the CEC in their licensing amendment proceeding. If the CEC grants a license to the project, then the District will issue an Authority to Construct.

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 proposed Oakley Generating Station. The proposed sources for Oakley Generating Station comply with the project risk requirements in accordance with the District's Regulation 2, Rule 5. The increased carcinogenic risk attributed to this project is less than 10.0 in one million, and the chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants are less than 1.0. The risk from each source individually is below 1.0 in a million maximum individual cancer risk, and the chronic hazard index is less than 0.20. In addition, the gas turbines and fire pump diesel engine will apply Best Available Control Technology for Toxics (TBACT). TBACT for the gas turbines is the use of an oxidation catalyst. TBACT for the fire pump diesel engine is a diesel PM emission rate of less than 0.15 gram per brake horsepower-hour (g/bhp-hr); the engine proposed for Oakley Generating Station has a diesel PM emission rate of 0.119 g/bhp-hr.

Regulation 2, Rule 6: Major Facility Review

After construction, the facility will be subject to Regulation 2, Rule 6, which implements the Title V program of the Federal Clean Air Act and 40 CFR 70, State Operating Permit Programs.

Pursuant to Section 404.1, the owner/operator of the Oakley Generating Station shall submit an application to the District for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Section 2-6-217 (Phase II Acid Rain Facility), the Oakley Generating Station 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 Oakley Generating Station gas turbine units will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72.

<u>40 CFR Part 72, Subpart A - Acid Rain Program</u>

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The gas turbines are affected units subject to the program in accordance with 40 CFR Part 72, Subpart A, Section 72.6(a)(3)(i).

<u>40 CFR Part 72, Subpart C – Acid Rain Permit Applications</u>

Subpart C, section 72.30(b)(2)(ii) requires that the applicant submit a complete Acid Rain Permit application 24 months before the gas turbines commence operation. Pursuant to 40 CFR Part 72.2, “commence operation” includes the start-up of the unit’s combustion chamber.

<u>40 CFR Part 73 - Sulfur Dioxide Allowance System</u>

Part 73 establishes the sulfur dioxide allowance system for tracking, holding, and transferring allowances. The applicant will be required to obtain sufficient SO_2 allowances for each operating year on March 1st (or February 29th in a leap year) of the following year.

<u>40 CFR Part 75 – Continuous Emission Monitoring</u>

Part 75 contains the continuous emission monitoring requirements for units subject to the Acid Rain program. The applicant will be required to meet the Part 75 requirements for monitoring, recordkeeping and reporting of SO_2, NO_x, and CO_2 emissions. The applicant will also need to meet Part 75 requirement for monitoring, recordkeeping, and reporting volumetric flowrate and opacity.

Regulation 6, Rule 1: Particulate Matter – General Requirements

<u>Opacity Requirements</u>
The gas turbines and auxiliary boiler are expected to comply with the visible emissions limitation in Section 6-1-301 (Ringelmann No. 1 Limitation) through the use of dry low-NO_x burner technology, good combustion practice, and natural gas. The evaporative fluid cooler is expected to comply with the visible emissions limitation in Section 6-1-301 (Ringelmann No. 1 Limitation) through the use of water with a maximum total dissolved solids content of 1,500 mg/l, which is not expected to result in visible emissions. The fire pump diesel engine is expected to comply with the visible emissions limitation in Section 6-1-303 (Ringelmann No. 2 Limitation) through the use of an EPA/CARB-certified Tier 3 engine and ultra-low sulfur diesel.

Visible Particles

The facility's sources are expected to comply with Section 6-1-305 (Visible Particles) with emissions of particles not causing annoyance to others or large enough to be visible as individual particles at the emission point or of such size and nature as to be visible individually as incandescent particles.

Particulate Weight Limitation

The gas turbines and auxiliary boiler are subject to 6-1-310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume, in actual conditions and calculated in accordance with Section 6-1-310.3 since the HRSG and auxiliary boiler involve heat transfer operations. The grain loading resulting from the operation of each gas turbine is 0.0008 gr/dscf @ 15% O_2 and from the boiler is 0.0048 gr/dscf @ 3% O_2. The grain loading resulting from the operation of each gas turbine is 0.0021 gr/dscf @ 6% O_2 and from the boiler is 0.0040 gr/dscf @ 6% O_2.

The fire pump diesel engine is subject to Section 6-1-310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. The grain loading resulting from the operation of the fire pump diesel engine is 0.029 gr/dscf @ 0% O_2. See Appendix A for calculations.

General Operations

The evaporative fluid cooler is subject to Regulation 6-1-311 (General Operations), which limits particulate matter emissions based on process weight. Based on 352,800 gallons of water per hour, the emission limit in Section 6-1-311 would be 40 lb PM/hour; emissions of PM based on a 0.003% drift rate and 1,500 total dissolved solids content would be 0.132 lb PM/hour, so the evaporative fluid cooler would comply with Section 6-1-311. See Appendix A for calculations.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements, but are subject to Regulation 6, Rule 1. However, the California Energy Commission will impose requirements for construction activities such as the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7: Odorous Substances

Section 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Section 7-303 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from the combined-cycle units will 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 auxiliary boiler are exempt from Regulation 8, Rule 2, “Miscellaneous Operations” per Section 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Section 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry, and it will emit less than 15 lb VOC/day.

The evaporative fluid cooler is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-114 since it is a closed loop cooling tower. The evaporated water, which is sprayed over the enclosed tubes containing the cooling fluid, does not contact the cooling fluid.

The use of solvents for cleaning and maintenance at the Oakley Generating Station is expected to be at a level that is exempt from permitting in accordance with Regulation 2, Rule 1, Section 118. The facility may utilize less than 20 gallons per year of solvent for wipe cleaning per Section 2-1-118.9 and remain exempt from permitting requirements. The facility may also utilize a cold cleaner for maintenance cleaning as long as the unit meets the exemption set forth in Section 2-1-118.4. The facility may also perform solvent cleaning and preparation using aerosol cans meeting the exemption set forth in Section 2-1-118.10. Any solvent usage exceeding the amounts in Section 2-1-118 would require a permit. In addition, any solvent usage in excess of a toxic air contaminant trigger level contained in Regulation 2, Rule 5 would require a permit.

The oil-water separator is exempt from Regulation 8, Rule 8, "Wastewater Collection and Separation Systems" per Section 8-8-113, since it is a stormwater sewer system for collection of stormwater that is segregated from a process wastewater collection system.

Regulation 9: Inorganic Gaseous Pollutants

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

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 9-1-301 (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 9-1-302 (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 and natural gas-fired auxiliary boiler are not expected to cause ground level SO_2 concentrations in excess of the limits specified in Section 301 and should easily comply with Section 302.

Section 9-1-304 (Fuel Burning (Liquid and Solid Fuels) prohibits burning of liquid fuel having a sulfur content in excess of 0.5% by weight. The fire pump diesel engine will be required to burn CARB diesel as defined in title 13, CCR, sections 2281 and 2282, which has a maximum sulfur content of 0.0015%.

<u>Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations</u>

The gas turbines shall comply with the Section 9-3-303 NO_x limit of 125 ppm by complying with a permit condition NO_x emission limit of 2.0 ppmvd @ 15% O_2. The auxiliary boiler shall comply with the Section 9-3-303 NO_x limit of 125 ppm by complying with a permit condition

NO_x emissions limit of 7 ppmvd @ 3% O_2. The proposed fire pump diesel engine is not subject to this regulation since it is not a heat transfer operation.

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

The gas turbines are not subject to Regulation 9, Rule 7 requirements per Section 9-7-110.5 (waste heat recovery boilers that are used to recover sensible heat from the exhaust of gas turbines).

The natural gas-fired boiler is subject to Regulation 9, Rule 7 requirements. The boiler shall comply with the NO_x emission limit of 30 ppm contained in Section 9-7-301.1, the future NO_x emission limit of 9 ppm contained in Section 9-7-307.5, and the CO emission limit of 400 ppmvd @ 3% O2 by using a boiler with manufacturer guaranteed emission rates of 7 ppmvd @ 3% O2 for NOx and 10 ppmvd @ 3% O_2 for CO or lower. The boiler is also subject to and expected to comply with 9-7-311 (Insulation Requirements), 312 (Stack Gas Temperature Limits), 313 (Tune-Up Requirements), 403 (Initial Demonstration of Compliance), and 503 (Records).

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

Because each of the gas turbines will be limited by permit condition to NO_x emissions of 2.0 ppmvd @ 15% O_2, respectively, they will comply with the Regulation 9-9-301.2 NO_x limitation of 5 ppmvd @ 15% O_2. The gas turbines exhaust emissions will be monitored by CEMs and will comply with 9-9-501, which requires each unit to have a CEM to monitor NO_x.

Regulation 10: Standards of Performance for New Stationary Sources

Regulation 10 incorporates Title 40 of the Code of Federal Regulations Part 60 into the Rules and Regulations of the Bay Area Air Quality Management District. The specific requirements applicable to the proposed Oakley Generating Station are discussed in Section 9.4, Federal Requirements, of this document.

9.2 State Requirements

California Health and Safety Code Sections 25531 to 25541
Title 19, Division 2, Chapter 4.5 California Accidental Release Prevention Program (CalARP)

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. These risks will be addressed in a number of ways under safety regulations and sound industry safety codes and standards. These safety measures include the Risk Management

Plan requirements pursuant to the California Accidental Release Prevention Program.[68] The Risk Management Plan 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. The Energy Commission will also be evaluating these risks further through its CEQA-equivalent environmental review process and will impose mitigating conditions as necessary to ensure that the risks are less than significant.

California Health and Safety Code Section 44300 et seq

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

Title 17, California Code of Regulations Section 93115

Section 93115 Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines applies to the fire pump diesel engine. Section 93115.5 requires the use of CARB diesel fuel, which the engine will use. Section 93115.6(a)(4) requires the engine to meet Tier 3 Off-Road Compression Ignition Engine Standards and allows the engine to be tested as required by the National Fire Protection Maintenance Association (NFPA) 25 standards. The proposed engine is certified to Tier 3 Off-Road Compression Ignition Engine Standards and will be limited to 49 hours per year for maintenance and testing. Section 93115.10 Recordkeeping, Reporting, and Monitoring requirements requires reporting and emissions submittal to the District, installation of a non-resettable hour meter, and recordkeeping requirements regarding hours of operation and fuel usage. The on-going applicable requirements will be included in the permit conditions.

Title 17, California Code of Regulations Sections 95100 to 95133, Article 2, Subchapter 10

The proposed Oakley Generating Station will be subject to the Mandatory Greenhouse Gas Emissions Reporting regulation. Potential GHG emissions were calculated in accordance with this regulation in Section 9.4 of this document. The proposed Oakley Generating Station would have to submit a greenhouse gas emissions data report and verification opinion to the California Air Resources Board each year.

[68] *See Contra Costa Generating Station Application for Certification*, Vol. 1, section 5.5.4.2.2 at p. 5.5-21. (available at: http://www.energy.ca.gov/sitingcases/oakley/documents/applicant/afc/index.php)

9.3 Federal Requirements

40 CFR Part 60 Subpart Dc

Subpart Dc "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units" applies to this facility. The boiler will comply with all applicable standards and limits in this regulation. Since the boiler will exclusively use natural gas, there are no applicable NO_x, SO_2, or opacity standards in this regulation.

Section 60.48c(a) requires notification of date of construction and actual startup along with design heat capacity and anticipated annual capacity factor. Section 60.48c(g)(2) requires the facility to record and maintain records of the amount of fuel combusted during each calendar month, which will also be included as a permit condition. Section 60.48c(g)(2) requires submittal of reports every six months.

40 CFR Part 60 Subpart IIII

Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines" applies to this facility. The fire pump diesel engine will comply with all applicable standards and limits by meeting the emission standards in section 60.4205(c), operating and maintaining the engine according to manufacturer's instructions per section 60.4206, using ultra low sulfur diesel fuel per section 60.4207, installing a non-resettable hour meter, and limiting maintenance and testing hours to 49 hours per year, which complies with the 100 hours per year limit in section 60.4211(e). The engine is exempt from notification requirements per 60.4214(b).

40 CFR Part 60 Subpart KKKK

Generally Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. However, the District has not sought delegation of the New Source Performance Standard (NSPS) contained in Subpart KKKK. Subpart KKKK "Standards of Performance for Stationary Gas Turbines" applies to this facility. The gas turbines will comply with all applicable standards and limits required by these regulations. The applicable emission limitations are summarized below:

TABLE 18: NEW SOURCE PERFORMANCE STANDARDS FOR COMBINED-CYCLE GAS TURBINES

Source	Requirement	Emission Limitation	Compliance Demonstration
Gas Turbines	Subpart KKKK §60.4320 (NO_x) §60.4330(SO_2)	0.43 lb NO_x/MW-hr, or 15 ppm NO_x as NO_2 @ 15%O_2; 0.9 lb SO_2/MW-hr, or 0.06 lb SO_2/MMBtu maximum No CO limit in Subpart KKKK No PM limit in Subpart KKKK	2.0 ppm NO_x as NO_2 @ 15%O_2 Permit Limit; 0.00281 lb SO_2/MMBtu Permit Limit

Section 60.4340(b)(1) requires continuous emissions monitors for NO_x, and NO_x initial and annual performance tests are to be satisfied by complying with Section 60.4405 RATA testing.

Section 60.4365(a) exempts the facility from SO_2 monitoring by requiring a contract for natural gas with 20 grains of sulfur or less per 100 standard cubic feet. The facility will use PUC-regulated natural gas and be conditioned to use natural gas with 1 grain of sulfur or less per 100 standard cubic feet.

Section 60.4375 requires submittal of reports of excess emissions and monitoring of downtime for all periods of unit operation, including startup, shutdown, and malfunction. The applicant is expected to maintain adequate records for Subpart KKKK reporting requirements. The gas turbines will be equipped with continuous emissions monitors for NO_x and CO and annual emission test will not be required for Subpart KKKK.

40 CFR 63 Subpart Q

Subpart Q "National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers" does not apply to this facility per section 63.400(a) since this regulation applies specifically to Industrial Process Cooling Towers that use chromium-based water treatment chemicals and are located at major sources of HAP emissions. Oakley Generating Station will not use chromium-based water treatment chemicals and is not a major source of HAP emissions, so Subpart Q does not apply.

40 CFR Part 63 Subpart YYYY

Subpart YYYY contains the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Combustion Turbines. This regulation has been stayed (Federal Register; April 7, 2004, Volume 69, Number 67) for a combustion turbine that is a lean premix gas fired unit or a diffusion flame gas fired unit.

The emissions standards contained in Subpart YYYY have been stayed for natural gas-fired combustion turbines per Section 63.6095. If a gas fired combustion turbine were subject to Subpart YYYY, then it would still need to comply with the Initial Notification requirements in Section 63.6145.

Subpart YYYY does not apply to the Oakley Generating Station gas turbines since the facility is not a major source of Hazardous Air Pollutants (HAPs). The Oakley Generating Station emits less than the major HAP thresholds of 10 tons/year of any single HAP, or 25 tons/year of aggregate HAP. Please note that ammonia, propylene, and sulfuric acid are not HAPs pursuant to section 112(b) of the Clean Air Act.

40 CFR Part 63 Subpart ZZZZ

Subpart ZZZZ "National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines" applies to this facility. Per Section 63.6590(c), the fire pump diesel engine will meet the requirements of this subpart by meeting the requirements of 40 CFR Part 60 Subpart IIII.

40 CFR Part 63 Subpart JJJJJJ

Subpart JJJJJJ "National Emission Standards for Area Sources: Industrial/Commercial/ Institutional Boilers" is proposed and the public comment period has been extended to August 3, 2010. If the regulation is adopted, the proposed auxiliary boiler at the Oakley Generating Station would not be subject to this subpart per section 63.11195(e) since it would be a gas-fired boiler.

40 CFR Part 64 – Compliance Assurance Monitoring (CAM)

Requirements for enhanced monitoring may apply to facilities that are required to obtain Part 70 (Title V or Major Facility Review) permits. If so, they would apply at the time of issuance of the Major Facility Review permit. Although, these requirements would not apply at the completion of construction, it is prudent to determine at this time if they will apply so that it can be determined whether the monitoring strategy would comply with CAM.

In general, the requirement applies if an emission unit, as defined in Section 64.1, is subject to a federally-enforceable emission limit for a pollutant, has emissions of the pollutant that are greater than the major source thresholds (100 tpy of any regulated air pollutant or 10 tpy of a HAP) and the emissions of that pollutant are abated by a control device. There are several exemptions.

In this case, NOx and CO from the gas turbines are controlled by SCR and a CO catalyst and CO from the auxiliary boiler may be controlled by a CO catalyst.

Monitoring for the NOx limits for the gas turbines is exempt in accordance with 40 CFR 64.2(b)(iii) because the monitoring is subject to the Acid Rain monitoring requirements in 40 CFR 75.

Monitoring for the CO limits for the gas turbines is required since the pre-abatement potential to emit of CO for each turbine is greater than 100 tons per year. Each gas turbine will have a continuous emission monitor for CO.

Monitoring for the CO limits for the auxiliary boiler is not required since the pre-abatement potential to emit of CO is less than 100 tons per year.

The estimated potential to emit from each gas turbine is calculated using the following parameters:
Fuel input: 2150 MMbtu/hr
CO Concentration: 9.0 ppmv (Normal Operation)
lb-mol CO = 28 lb CO
8743 scf flue gas/MMbtu @ 0% O2
386.8 dscf/lbmol

At 9.0 ppm
(9.0 ppmv)(20.95 - 0)/(20.95 - 15) = 31.69 ppmv, dry @ 0% O2

(31.69/106)(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MM Btu) = 0.0201 lb CO/MMBtu

(2150 MMbtu/hr)(0.0201 lb CO/MMBtu) = 43.12 lb CO/hr

At 5390 hours/year of normal operation + 25 cold starts + 275 hot starts + 300 shutdowns
= (5390 hours)(43.12 lb CO/hr) + (25 cold start)(360 lb/cold start) + (275 hot start)(85 lb/hot start) + (300 shutdowns)(140 lb/shutdown)
= 153 TPY CO/turbine

The auxiliary boiler may be required to be abated by an oxidation catalyst if the CO limit cannot be met without abatement. If the oxidation catalyst is needed, pre-abatement CO potential to emit is estimated below.

Fuel input: 50.6 MMbtu/hr
CO Concentration: 50.0 ppmv
lb-mol CO = 28 lb CO
8743 scf flue gas/MMbtu @ 0% O2
386.8 dscf/lbmol

At 50.0 ppm
(50.0 ppmv)(20.95 - 0)/(20.95 - 15) = 176.1 ppmv, dry @ 0% O2

(176.1/106)(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MM Btu) = 0.1114 lb CO/MMBtu

(50.6 MMbtu/hr)(0.1114 lb CO/MMBtu) = 5.64 lb CO/hr

At 4324 hours/year
= (4324 hour/year)(5.64 lb CO/hr)
= 12.2 TPY

Since pre-abatement potential to emit for CO is less than 100 tons per year, the auxiliary boiler is not subject to CAM.

40 CFR Part 70, State Operating Permit Programs
These requirements are discussed in Section 8.2 under Regulation 2, Rule 6, Major Facility Review, which implements Part 70.

40 CFR Part 72, Subpart A – Acid Rain Program

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The gas turbines are affected units subject to the program in accordance with 40 CFR Part 72, Subpart A, Section 72.6(a)(3)(i).

40 CFR Part 72, Subpart C – Acid Rain Permit Applications

Subpart C, section 72.30(b)(2)(ii) requires that the applicant submit a complete Acid Rain Permit application 24 months before the gas turbines commence operation. Pursuant to 40 CFR Part 72.2, "commence operation" includes the start-up of the unit's combustion chamber.

40 CFR Part 73 – Sulfur Dioxide Allowance System

Part 73 establishes the sulfur dioxide allowance system for tracking, holding, and transferring allowances. The applicant will be required to obtain sufficient SO_2 allowances for each operating year on March 1st (or February 29th in a leap year) of the following year.

40 CFR Part 75 – Continuous Emission Monitoring

Part 75 contains the continuous emission monitoring requirements for units subject to the Acid Rain program. The applicant will be required to meet the Part 75 requirements for monitoring, recordkeeping and reporting of SO_2, NO_x, and CO_2 emissions. The applicant will also need to meet Part 75 requirement for monitoring, recordkeeping, and reporting volumetric flowrate and opacity.

40 CFR Part 98

Part 98 Mandatory Greenhouse Gas Reporting, requires certain facilities, including electrical generation facilities such as Oakley Generating Station, to monitor, keep records of, and report GHG emissions every March 31 for the previous calendar year.

9.4 Greenhouse Gases

Climate change poses a significant risk to the Bay Area with such 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. The generation of electricity from burning natural gas produces air emissions known as greenhouse gases (GHGs) in addition to the criteria air pollutants. GHGs are known to contribute to the warming of the earth's atmosphere. These include primarily carbon dioxide, nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NO_x or oxides of nitrogen), and methane (unburned natural gas). Also included are sulfur hexafluoride (SF_6) from transformers, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chillers. The proposed Oakley Generating Station would use evaporative inlet air cooling, which uses water, and not HFCs or PFCs.

The California Global Warming Solutions Act of 2006 (AB32) requires the California Air Resources Board (ARB) to adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990 to be achieved by 2020. To achieve this, ARB has 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 facility will also be required to report GHG emissions to CARB, the District, and US EPA. In 2008, the District placed a fee on GHG emissions from large stationary sources of GHGs.

The GHG emissions estimates for Oakley Generating Station are shown below.

TABLE 19: OAKLEY GENERATING STATION GHG EMISSIONS

	Fuel Usage	Emission Factor	Emission Factor	Emission Factor	GHG Emissions	Global Warming	CO2 equivalents
	(MMBtu/year)	(kg CO2/MMBtu)	(g CH4/MMBtu)	(g N2O/MMBtu)	(metric tons/year)	Potential	(metric tons/year)
Gas Turbines	35397277						
CO2		52.87			1.871E+06	1	1871454.035
CH4			0.9		3.186E+01	21	669.009
N2O				0.1	3.540E+00	310	1097.316
Auxiliary Boiler	218606						
CO2		52.87			1.156E+04	1	11557.699
CH4			0.9		1.967E-01	21	4.132
N2O				0.1	2.186E-02	310	6.777
Fire Pump Engine	136						
CO2		73.10			9.942E+00	1	9.942
CH4			3.0		4.080E-04	21	0.009
N2O				0.6	8.160E-05	310	0.025
Circuit Breakers	**Total Capacity of SF6**	**leak rate**		**GHG Emissions**	**GHG Emissions**	**Global Warming**	**CO2 equivalents**
	(lbs)	**(%)**		**(kg/year)**	**(metric tons/year)**	**Potential**	**(metric tons/year)**
SF6	200	0.50%		0.454	4.536E-04	23900	10.841
TOTAL GHG Emissions (CO2 equivalent, metric tons/year)							**1,884,809.8**

Oakley Generating Station has the potential to emit 1,884,809.8 metric tons of CO_2 equivalents per year using the ARB Mandatory Reporting Rule calculation methodology.

The Oakley Generating Station combined-cycle gas turbines will have a gross electrical efficiency of 56% at 59ºF and a relative humidity of 60%.[69] The Oakley Generating Station will have a net facility heat rate of 6,752 (HHV) Btu/KW-hr at 59ºF and a relative humidity of 60%.[70]

On September 29, 2006, Governor Arnold Schwarzenegger signed into law Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006). The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the California Energy Commission and the California Public Utilities Commission.

The Energy Commission has designed regulations that, among other things, establish a standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lbs CO_2 per megawatt-hour (MWh). A utility must submit a compliance filing with the CEC upon committing to an investment that is required to meet the Emission Performance Standard (Compliance Filing).

The applicant has estimated that the proposed Oakley Generating Station will meet the Emission Performance Standard of 1,100 lbs CO_2 per megawatt-hour (MWh):

At ISO conditions:

624 MW (net)
2102 MMBtu/hr/turbine (HHV) x 2 turbines x 52.87 kg CO_2/MMBtu /1000
= 222.27 metric tons CO_2/hr

222.27 metric tons CO_2/hr / 624 MW = 0.356 metric tons CO_2/MWh
0.356 metric tons CO_2/MWh x 2204.6 lb/metric ton = 784.8 lb CO_2/MWh

As published in the Federal Register on June 3, 2010, beginning January 2, 2011, only stationary sources that are major for a regulated new source review pollutant that is not a GHG and will emit or have the potential to emit 75,000 TPY CO_2 equivalent or more are subject to Prevention of Significant Deterioration for GHGs.[71] Beginning July 1, 2011, new stationary sources that will emit or have the potential to emit 100,000 TPY CO_2 equivalent or more are subject to Prevention

[69] *See* Radback Energy *Supplemental Filing Air Quality and Public Health Revised April 7, 2010, Application for Certification for Oakley Generating Station Project*, at p. Appendix 5.1F-33.
[70] *See* Radback Energy *Supplemental Filing Air Quality and Public Health Revised April 7, 2010, Application for Certification for Oakley Generating Station Project*, Table 5.1-1 at p. 5.1-3.
[71] *See* 40 CFR Part 52.21(b)(49)(iv)-(v).

of Significant Deterioration for GHG. Therefore, Oakley Generating Station is not required to address GHG emissions under the Clean Air Act at this time.

As the lead agency under the CEQA-equivalent process, the CEC will be required to quantify and assess GHG emissions from the Oakley Generating Station to evaluate the facility's compliance with applicable laws, ordinances, regulations and standards, and the potential impacts and benefits associated with adding Oakley Generating Station to the electricity system.

9.5 Environmental Justice

The 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 District has worked to fulfill this commitment in the current permitting action, although there is no legal requirement that the District undertake an environmental justice analysis for this permitting action.[72] Nevertheless, regardless of any applicable legal requirements, the District considers environmental justice concerns to be sufficiently important to warrant a discussion in this document.

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 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 District has found that the maximum lifetime cancer risk associated with the facility is 1.56 in one million, and that the maximum chronic Hazard Index would be 0.0832 and the maximum acute Hazard Index would be 0.2665. These risk levels are below what the District considers to be significant. In particular, these risk levels are less than the thresholds of significance that the District's Board of Directors recently adopted as indicating whether health risk impacts would be significant in the context of a CEQA review.[73] The District anticipates that there will be no significant impacts due to air emissions related to the Oakley Generating Station after all of the mitigations required by District Rules and the California Energy Commission are implemented. The District does not anticipate a significant adverse impact on any community due to air emissions from the Oakley Generating Station; therefore, there will be no significant disparate adverse impact on any Environmental Justice community located near the facility.

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[72] The environmental justice analysis requirements of the federal Executive Order 12898 do not apply here because the District is not issuing a federal permit, and state requirements for evaluating environmental justice impacts as part of the overall CEQA environmental review are handled through the CEC's CEQA-equivalent. (Note that Title VI civil rights requirements applicable to agencies that receive federal funds impose anti-discriminatory requirements on the agency's programs as a whole, and do not impose any specific requirements for an environmental justice analysis for individual permitting actions.)

[73] *See* BAAQMD Air Quality CEQA Threshold of Significance (June 2, 2010), available at: www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Adopted%20Thresholds%20Table_6_2_10.ashx.

10. Proposed Permit Conditions

The District is proposing the following permit conditions to ensure that the project complies with all applicable District, state, and federal Regulations. The proposed conditions would limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. The permit conditions 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) will ensure that daily and annual emission rate limitations are not exceeded.

For the gas turbines and auxiliary boiler, compliance with CO and NO_X limitations would be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up, shutdown, and combustor tuning. Compliance with POC, SO_2, and PM_{10} mass emission limits would be verified by source testing.

In addition to permit conditions that apply to steady-state operation of each gas turbine power train, the District is proposing conditions that govern equipment operation during the initial commissioning period when the gas turbine 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 and adjustment of control systems. Parts 1 through 10 of the proposed permit conditions for the combined-cycle gas turbines apply to this commissioning period and are intended to minimize emissions during the commissioning period.

Proposed Oakley Generating Station Permit Conditions

Definitions:

Hour:	Any continuous 60-minute period
Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 midnight or 0000 hours
Year:	Any consecutive twelve-month period of time
Rolling 3-hour period:	Any consecutive three-clock hour period, not including start-up or shutdown periods
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 hours
MMBtu:	million British thermal units
Gas Turbine Cold Start-up	A gas turbine startup that occurs more than 48 hours after a gas turbine shutdown, and is limited in time to the lesser of (i) the first 90 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or (ii) the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves the first of two consecutive CEM data points in compliance with the emission concentration limits of Parts 16(b) and 16(d)
Gas Turbine Hot/Warm Start-up	A gas turbine startup that occurs within 48 hours of a gas turbine shutdown, and is limited in time to the lesser of (i) the first 30 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or (ii) the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves the first of two consecutive CEM data points in compliance with the emission concentration limits of Parts 16(b) and 16(d)
Gas Turbine Shutdown:	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 Parts 16(b) and 16(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Combustor Tuning:	The period of time, not to exceed 6 operating hours per tuning event, in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the gas turbine manufacturer, to ensure safe and reliable steady-state operation, and to minimize NO_X and CO emissions.

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, the exhaust of Gas Turbine (S-1), and P-2, the exhaust of Gas Turbine (S-2), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-3, the exhaust of Auxiliary Boiler (S-3), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the OGS construction contractor to ensure 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 Commissioning 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 Commissioning Period shall terminate when the plant has completed performance and emissions testing.
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
OGS:	Oakley Generating Station
Owner/operator:	The owner/operator of Oakley Generating Station
Total Particulate Matter:	The sum of all filterable and all condensable particulate matter.

GE 7FA Combined-Cycle Gas Turbines

Applicability:

Parts 1 through 10 of this condition shall only apply during the commissioning period as defined above. Unless otherwise indicated, Parts 11 through 30 of this condition shall apply after the commissioning period has ended.

Conditions for the Commissioning Period for GE 7FA Gas Turbines (S-1 and S-2)

1. The owner/operator shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 and S-2 Gas Turbines to the maximum extent possible during the commissioning period. (Basis: BACT, Regulation 2, Rule 2, Section 409)
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 and S-2 Gas Turbines combustors to minimize the emissions of carbon monoxide and nitrogen oxides. (Basis: BACT, Regulation 2, Rule 2, Section 409)
3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall install, adjust, and operate the A-2 and A-4 Oxidation Catalysts and A-1 and A-3 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 and S-2 Gas Turbines. (Basis: BACT, Regulation 2, Rule 2, Section 409)
4. The owner/operator shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 and S-2 Gas Turbines describing the procedures to be followed during the commissioning of the gas 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 and S-2) 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-2) sooner than 28 days after the District receives the commissioning plan. (Basis: Regulation 2, Rule 2, Section 419)
5. During the commissioning period, the owner/operator shall demonstrate compliance with Parts 7, 8, and 9 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters and emission concentrations:

   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 and S-2). 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. (Basis: Regulation 2, Rule 2, Section 419)

6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in Part 5 prior to first firing of the Gas Turbines (S-1 and S-2). 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 instruments shall operate at all times of operation of S-1 and S-2 including start-up, shutdown, upset, and malfunction, except as allowed by BAAQMD Regulation 1-522, BAAQMD Manual of Procedures, Volume V. If necessary to comply with this requirement, the owner/operator shall install dual-span monitors. The type, specifications, and location of these monitors shall be subject to District review and approval. (Basis: Regulation 2, Rule 2, Section 419)

7. The owner/operator shall not fire S-1 and S-2 Gas Turbine without abatement of nitrogen oxide emissions by the corresponding SCR System A-1 and A-3 and/or abatement of carbon monoxide emissions by the corresponding Oxidation Catalyst A-2 and A-4 for more than a combined total of 831 hours during the commissioning period. Such operation of any Gas Turbine (S-1, S-2) 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 831 firing hours without abatement shall expire. (Basis: BACT, Regulation 2, Rule 2, Section 409)

8. 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, and S-2) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in Part 43. (Basis: Regulation 2, Rule 2, Section 409)

9. The owner/ operator shall not operate the Gas Turbines (S-1 and S-2) in a manner such that the pollutant emissions from each gas turbine 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-2). (Basis: BACT, Regulation 2, Rule 2, Section 409)

NO_X (as NO_2)	2,380.8 pounds per calendar day	148.7 pounds per hour
CO	13,303 pounds per calendar day	700 pounds per hour

10. Within 90 operating days after first fire of each Gas Turbine, the owner/operator shall conduct District- and CEC-approved source tests for that Gas Turbine to determine compliance with the emission limitations specified in Part 17. 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. 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 Part. 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. (Basis: Regulation 2, Rule 2, Section 419)

Conditions for the GE 7FA Combined-Cycle Gas Turbines (S-1 and S-2)

11. The owner/operator shall fire the Gas Turbines (S-1 and S-2) 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 and S-2 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 OGS. (Basis: BACT for SO_2 and PM_{10})
12. The owner/operator shall not operate the units such that the heat input rate to each Gas Turbine (S-1 and S-2) exceeds 2,150 MMBtu (HHV) per hour. (Basis: BACT for NO_X)
13. The owner/operator shall not operate the units such that the heat input rate to each Gas Turbine (S-1 and S-2) exceeds 51,600 MMBtu (HHV) per day. (Basis: Cumulative Increase for PM_{10})
14. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 and S-2) exceeds 35,397,277 MMBtu (HHV) per year. (Basis: Offsets)
15. The owner/operator shall ensure that each Gas Turbine (S-1, S-2) is abated by the properly operated and properly maintained Selective Catalytic Reduction (SCR) System A-1 or A-3 and Oxidation Catalyst System A-2 or A-4 whenever fuel is combusted at those sources and the corresponding SCR catalyst bed (A-1 or A-3) has reached minimum operating temperature. (Basis: BACT for NO_X, POC and CO)
16. The owner/operator shall ensure that the Gas Turbines (S-1, S-2) comply with the following limits. The limits in this part do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (Basis: BACT and Regulation 2, Rule 5)
    a) Nitrogen oxide mass emissions (calculated as NO_2) at each exhaust point P-1 and P-2 (exhaust point for S-1 and S-2 Gas Turbine after abatement by A-1 and A-3 SCR System) shall not exceed 15.52 pounds per hour, averaged over any 1-hour period. (Basis: Cumulative Increase for NO_X)
    b) The nitrogen oxide emission concentration at each exhaust point P-1 and P-2 shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (Basis: BACT for NO_X)

c) Carbon monoxide mass emissions at each exhaust point P-1 and P-2 shall not exceed 9.45 pounds per hour, averaged over any 1-hour period. (Basis: Cumulative Increase for CO)

d) The carbon monoxide emission concentration at each exhaust point P-1 and P-2 shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2 averaged over any 1-hour period. (Basis: BACT for CO)

e) Ammonia (NH_3) emission concentrations at each exhaust point P-1 and P-2 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 each SCR System A-1 and A-3. The correlation between the gas turbine heat input rates, A-1 and A-3 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with Part 25 or a District approved alternative method. (Basis: Regulation 2, Rule 5)

f) Precursor organic compound (POC) mass emissions (as CH_4) at each exhaust point P-1 and P-2 shall not exceed 2.71 pounds per hour. (Basis: Cumulative Increase for POC)

17. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, and S-2) during a start-up or shutdown does not exceed the limits established below. (Basis: BACT Limit for Non-Steady-State Operation)

Pollutant	**Hot/Warm Startup (lb/startup)**	**Maximum Emissions During an Hour Containing a Hot/Warm Startup (lb/hr)**	**Maximum Emissions Per Cold Startup (lb/startup)**	**Maximum Emissions During an Hour Containing a Cold Startup (lb/hr)**	**Maximum Emissions Per Shutdown (lb/shutdown)**	**Maximum Emissions During an Hour Containing a Shutdown (lb/hr)**
NO_X (as NO_2)	22.3	33.9	96.3	99.9	39.3	46.8
CO	85.2	92.2	360.2	362.4	140.2	144.7
POC (as CH_4)	31.1	33.1	67.1	67.7	17.1	18.4

18. The owner/operator shall not perform combustor tuning on each Gas Turbine (S-1 or S-2) more than twice in any consecutive 12 month period. Each tuning event shall not exceed 6 hours. Combustor tuning shall only be performed on one gas turbine per day. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. The emissions during combustor tuning from each gas turbine shall not exceed the hourly limits established below, and shall not exceed hourly limits established by the District based on emissions data obtained during the first tuning event for each turbine. The

owner/operator shall measure and record mass emissions of NOx and CO using the continuous emission monitors during tuning. The owner/operator shall measure POC emissions during the first tuning after the first turbine has been commissioned using a District-approved source test method. The owner/operator shall submit the record of the NOx, CO, and POC emissions during the first tuning event after the first turbine has been commissioned to the District within 60 days after the first tuning event. The District shall establish mass emissions limits for the future tuning events based on this test data and shall notify the owner/operator of these limits. (Basis: BACT, Offsets, Cumulative Increase)

Pollutant	Emissions Limit (lb/hr)
NO_X (as NO_2)	96
CO	360
POC (as CH_4)	67

19. The owner/operator shall not allow total emissions from each Gas Turbine (S-1 or S-2), including emissions generated during gas turbine start-ups, and shutdowns to exceed the following limits during any calendar day (except for days during which combustor tuning events occur, which are subject to Part 20 below):
    a) 488 pounds of NO_X (as NO_2) per day (Basis: Cumulative Increase)
    b) 715 pounds of CO per day (Basis: Cumulative Increase)
    c) 146 pounds of POC (as CH_4) per day (Basis: Cumulative Increase)
20. The owner/operator shall not allow total emissions from each Gas Turbine (S-1 or S-2), including emissions generated during gas turbine start-ups, shutdowns, and combustor tuning events to exceed the following limits during any calendar day on which a tuning event occurs:
    a) 971 pounds of NO_X (as NO_2) per day (Basis: Cumulative Increase)
    b) 2818 pounds of CO per day (Basis: Cumulative Increase)
    c) 531 pounds of POC (as CH_4) per day (Basis: Cumulative Increase)
21. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per Part 24) from the Gas Turbines (S-1, S-2) combined to exceed the following limits:

    Formaldehyde 16,636.1 pounds per year
    Benzene 462.9 pounds per year
    Specified polycyclic aromatic hydrocarbons (PAHs) 4.54 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. (Basis: Regulation 2, Rule 5)

22. The owner/operator shall demonstrate compliance with Parts 12 through 14, 16(a) through 16(d), 17 (NO_X, and CO limits), 18 (NO_X and CO limits), 19(a), 19(b), 20(a), 20(b), 43(a) and 43(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods). If necessary to comply with this requirement, the owner/operator shall install dual-span monitors. The owner/operator shall monitor for all of the following parameters and record each parameter at least every 15 minutes (excluding normal calibration periods):

    a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 and S-2
    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-2 SCR Systems

    The owner/operator shall use the parameters measured above and District approved calculation methods to calculate and record the following parameters for each gas turbine (S-1 and S-2):

    d) Corrected NO_X concentration and corrected CO concentration, averaged for each clock hour
    e) Corrected NO_X concentration and corrected CO concentration, averaged for each calendar day

    The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate and record the following parameters for each gas turbine (S-1 and S-2) and totaled for S-1 and S-2:

    f) For each rolling three hour period, the heat input rate in MMBtu (HHV) per hour
    g) For each calendar day, the average hourly heat input rate in MMBtu (HHV) per hour and total daily heat input rate in MMBtu (HHV) per day
    h) For each consecutive twelve month period, the total heat input rate in MMBtu (HHV) per year
    i) For each clock hour, the NO_X mass emission rate (as NO_2) and CO mass emissions rate in pounds per hour
    j) For each calendar day, the NO_X mass emission rate (as NO_2) and CO mass emissions rate in pounds per day
    k) For each consecutive 12-month period, the monthly NO_X (as NO_2) and CO mass emissions rates in pounds per month and annual NO_X and CO mass emissions rates in pounds per year and tons per year

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

23. To demonstrate compliance with Parts 16(f), 19(c), 20(c), and 43(c) the owner/operator shall calculate and record on a daily basis, the precursor organic compound (POC) mass emissions from each power train. The owner/operator shall use the actual heat input rates measured pursuant to Part 22, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under Part 26 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

    a) For each calendar day, POC mass emissions, summarized for each gas turbine and S-1 and S-2 combined

    b) For each consecutive 12-month period, the cumulative total POC mass emissions for each gas turbine and S-1 and S-2 combined.

    (Basis: Offsets, Cumulative Increase)

24. To demonstrate compliance with Part 21, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAHs. The owner/operator shall calculate the maximum projected annual emissions using the combined maximum annual heat input rate of 35,397,277 MMBtu/year for S-1 and S-2 combined and the highest emission factor (pounds of pollutant per MMBtu of heat input) determined by the most recent of any source test of the S-1 or S-2 Gas Turbines. 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. (Basis: Regulation 2, Rule 5)

25. Within 90 operating days of first fire of each of the OGS GE 7FA units, the owner/operator shall conduct a District-approved source test on each corresponding exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with Part 16(e). The source test shall determine the correlation between the heat input rates of the gas turbine, A-1 or A-3 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 (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 Part 16(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. (Basis: Regulation 2, Rule 5)

26. Within 90 operating days of first fire of each of the OGS GE 7FA units and, at a minimum, 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 is operating at maximum load to determine compliance with Parts 16(a), 16(b), 16(c), 16(d), 16(f), and to establish the emissions factors to be used to demonstrate compliance with Parts 43(d) and 43(e); and while each Gas Turbine is operating at minimum load to determine compliance with Parts 16(c) and 16(d); and to verify the accuracy of the continuous emission monitors required in Part

22. The owner/operator shall test for (as a minimum each year): 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 PM_{10} emissions including condensable particulate matter. The owner/operator may conduct source tests of individual compounds listed in this part separately. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. The owner/operator may perform up to four tests per year for PM_{10} emissions including condensable particulate matter. (Basis: BACT, Offsets, Cumulative Increase)

27. 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 any measurement of the total particulate matter or 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. (Basis: BACT, Regulation 2, Rule 2, Section 419)

28. Within 90 operating days of first fire of the second of the OGS GE 7FA gas turbines and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on one of the following exhaust points P-1 or P-2 while the Gas Turbine is operating at maximum allowable operating rates to demonstrate compliance with Part 21. 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 Part 24 for any of the compounds are less than 50% of the levels listed in Part 21, then the owner/operator may discontinue future testing for that pollutant. (Basis: Regulation 2, Rule 5)

29. Within 90 days of start-up of each of the OGS GE 7FA gas turbines and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on one of the two exhaust points P-1 or P-2 while the gas turbine is operating at maximum heat input rate to demonstrate compliance with the total sulfuric acid mist emission rate for S-1 and S-2 of 6.3 tons per year. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4, and the sulfur content of the fuel. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Basis: Regulation 2, Rule 5)

30. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 155.5 feet above grade level at the stack base. (Basis: Regulation 2, Rule 5)

Auxiliary Boiler (S-3)

31. The owner/operator shall submit manufacturer's specifications and emissions guarantees for NO_x and CO for the Auxiliary Boiler (S-3) to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of Auxiliary Boiler (S-3). (Basis: Regulation 2, Rule 2, Section 419)

32. If Oxidation Catalyst (A-5) is required, the owner/operator shall install, adjust, and operate the A-5 Oxidation Catalyst at the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, to minimize the emissions of carbon monoxide from S-3 Auxiliary Boiler. (Basis: Regulation 2, Rule 2, Section 419)

33. The heat input rate to the Auxiliary Boiler (S-3) shall not exceed 50.6 MMBtu per hour, averaged over any rolling 3-hour period. (Basis: Cumulative Increase)

34. The heat input rate to the Auxiliary Boiler (S-3) shall not exceed 218,606 MMBtu per year. (Basis: Cumulative Increase)

35. The owner/operator of the Auxiliary Boiler (S-3) shall meet all of the requirements listed in below.

    a) Nitrogen oxide emissions at P-3 (the exhaust point for the Auxiliary Boiler) shall not exceed 9.8 pounds per day, calculated as NO_2. (Basis: Regulation 2-1-403)

    b) Carbon monoxide emissions at P-3 shall not exceed 9.8 pounds per day. (Basis: Regulation 2-1-403)

    c) POC emissions at P-3 shall not exceed 2.8 pounds per day. (Basis: Regulation 2-1-403)

36. The owner/operator shall demonstrate compliance with Parts 35(a), 35(b) and 43(a) and 43(b) by using properly operated and maintained continuous monitors (during all hours of operation including auxiliary boiler start-up, tuning, and shutdown periods). The owner/operator shall monitor for all of the following parameters and record each parameter at least every 15 minutes (excluding normal calibration periods):

    a) Firing Hours and Fuel Flow Rates

    b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_X) concentration, and carbon monoxide (CO) concentration at exhaust point P-3

    The owner/operator shall use the parameters measured above and District approved calculation methods to calculate and record the following parameters for the Auxiliary Boiler (S-3):

    c) Corrected NO_X concentration and corrected CO concentration, averaged for each clock hour

    d) Corrected NO_X concentration and corrected CO concentration, averaged for each calendar day

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate and record the following parameters for Auxiliary Boiler (S-3):

e) For each rolling three hour period, the heat input rate in MMBtu (HHV) per hour

f) For each calendar day, the average hourly heat input rate in MMBtu (HHV) per hour and total daily heat input rate in MMBtu (HHV) per day

g) For each consecutive twelve month period, the total heat input rate in MMBtu (HHV) per year

h) For each clock hour, the NO_X mass emission rate (as NO_2) and CO mass emissions rate in pounds per hour

i) For each calendar day, the NO_X mass emission rate (as NO_2) and CO mass emissions rate in pounds per day

j) For each consecutive 12-month period, the monthly NO_X (as NO_2) and CO mass emissions rates in pounds per month and annual NO_X (as NO_2) and CO mass emissions rates in pounds per year and tons per year

(Basis: 1-520.1, 9-7-307, BACT, Offsets, Cumulative Increase)

37. To demonstrate compliance with Part 35(c) the owner/operator shall calculate and record on a daily basis, the precursor organic compound (POC) mass emissions from the auxiliary boiler. The owner/operator shall use the actual heat input rates measured pursuant to Part 36, and CEC and District-approved emission factors developed pursuant to source testing under Part 38 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

a) For each calendar day, POC mass emissions, summarized for S-3

b) For each consecutive 12-month period, the cumulative total POC mass emissions for S-3.

(Basis: Offsets, Cumulative Increase)

38. Within 90 operating days after first fire of Auxiliary Boiler (S-3), the owner/operator shall conduct a District-approved source test on exhaust point P-3 while the auxiliary boiler is operating at maximum load to determine emission factors for POC, PM_{10} and SO_x. 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 PM_{10} emissions including condensable particulate matter. 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 Part. 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. (Basis: Regulation 2, Rule 2, Section 419)

Conditions for the Fire Pump Diesel Engine (S-4)

39. The owner/operator shall fire the Fire Pump Diesel Engine (S-4) exclusively on diesel fuel having a sulfur content no greater than 0.0015% by weight. (Regulation 2, Rule 5, Cumulative Increase, "Stationary Diesel Engine ATCM", CA Code of Regulations, Title 17, Section 93115.5(a))
40. The owner/operator shall operate the Fire Pump Diesel Engine (S-4) for no more than 49 hours per year for the purpose of reliability testing and non-emergency operation. (Regulation 2, Rule 5, Cumulative Increase, "Stationary Diesel Engine ATCM", CA Code of Regulations, Title 17, Section 93115.6(a)(4)(A))
41. The owner/operator shall operate the Fire Pump Diesel Engine (S-4) only when a non-resettable totalizing hour meter (with a minimum display capability of 9,999 hours) is installed, operated and properly maintained. (Basis: BAAQMD Regulation 9-8-530, "Stationary Diesel Engine ATCM", CA Code of Regulations, Title 17, Section 93115.10(e)(1))
42. The owner/operator shall maintain the following monthly records for Fire Pump Engine (S-4) in a District-approved log for at least 5 years.
    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 for emergency use.
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage.

    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. (Basis: BAAQMD Regulation 9-8-530, "Stationary Diesel Engine ATCM", CA Code of Regulations, Title 17, Section 93115.10(g))

Conditions for the Combined-Cycle Gas Turbines (S-1 and S-2), Auxiliary Boiler (S-3), and Fire Pump Engine (S-4)

43. The owner/operator shall not allow total combined emissions from the Gas Turbines (S-1 and S-2), including emissions generated during gas turbine start-ups, combustor tuning, shutdowns, and malfunctions, the auxiliary boiler (S-3), including emissions generated during auxiliary boiler start-ups, tune-ups, shutdowns, and malfunctions, and the fire pump diesel engine (S-4), including non-emergency and emergency operation, to exceed the following limits during any consecutive twelve-month period:
    a) 98.78 tons of NO_x (as NO_2) (Basis: Offsets)
    b) 98.82 tons of CO (Basis: Cumulative Increase)
    c) 29.49 tons of POC (as CH_4) (Basis: Offsets)

d) 63.78 tons of PM_{10} (Basis: Cumulative Increase)

e) 12.55 tons of SO_2 (Basis: Cumulative Increase)

Compliance with the limits in this part shall be determined using the following procedures:

Emissions of PM_{10} and SO_2 from each gas turbine shall be calculated by multiplying turbine fuel usage times an emission factor determined by source testing of the turbine conducted in accordance with Part 26. The emission factor for each turbine shall be based on the average of the emissions rates observed during the 4 most recent source tests on that turbine (or, prior to the completion of 4 source tests on a turbine, on the average of the emission rates observed during all source tests on the turbine).

Emissions of PM_{10}, SO_2, and POC from the auxiliary boiler shall be calculated by multiplying auxiliary boiler fuel usage times an emission factor determined by source testing of the auxiliary boiler conducted in accordance with Part 38.

The owner/operator shall calculate emissions from the fire pump diesel engine from the hours of operation recorded in Part 42 and the following emission factors:

NO_x: 2.62 g/hp-hr

CO: 0.67 g/hp-hr

POC: 0.14 g/hp-hr

PM: 0.119 g/hp-hr

SO_x: 0.004 g/hp-hr

44. To demonstrate compliance with Part 43, the owner/operator shall record the total emissions for each consecutive 12-month period. The owner/operator shall calculate emissions of each pollutant listed in Part 43(a) through (e) from the gas turbines, auxiliary boiler, and fire pump diesel engine for each calendar month using the calculation procedures established in Part 43, and shall calculate annual emissions to determine compliance with the limits listed in Part 43(a) through (e) by summing the monthly totals for the previous 12 months. (Basis: Regulation 2, Rule 2, Section 419)

45. The owner/operator 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. (Basis: Regulation 2, Rule 1, Section 403)

46. The owner/operator 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. (Basis: Regulation 2, Rule 1, Section 403, Regulation 2, Rule 6, Section 501)

47. The owner/operator 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. (Basis: Regulation 2, Rule 1, Section 403)

48. The owner/operator 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, except that the facility shall provide four sampling ports that are at least 6 inches in diameter in the same plane of each gas turbine stack (P-1, P-2). (Basis: Regulation 1, Section 501)

49. Within 180 days of the issuance of the Authority to Construct for the OGS, 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 Parts 10, 25, 26, 28, 29, 38, and 39. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Basis: Regulation 1, Section 501)

50. The owner/operator shall ensure that the OGS complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Basis: Regulation 2, Rule 7)

11. Preliminary Determination

The APCO has made a preliminary determination that the proposed Oakley Generating Station power plant, which is composed of the permitted sources listed below, complies with all applicable District, state and federal air quality rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-1 Gas Turbine Generator #1, GE Frame 7FA, Natural Gas-Fired, 213 MW, 2150 MMBtu/hr (HHV) maximum rated capacity with high-efficiency inlet air filter; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-2 Gas Turbine Generator #2, GE Frame 7FA, Natural Gas-Fired, 213 MW, 2150 MMBtu/hr (HHV) maximum rated capacity with high-efficiency inlet air filter; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-3 Auxiliary Boiler, Natural Gas-Fired, 50.6 MMBtu/hr (HHV) maximum rated capacity (abated by A-5 Oxidation Catalyst if required)

S-4 Fire Pump Diesel Engine, Clarke JW6H-UFAD80, 400 hp, 2.78 MMBtu/hr maximum rated heat input

S-5 Evaporative Fluid Cooler, 3-Cell, 5,880 gallons per minute (Exempt from District Permit requirements per Regulation 2, Rule 1, Section 128.4)

S-6 Oil-Water Separator, 120 gallons per hour (Exempt from District Permit requirements per Regulation 2, Rule 1, Section 103 and Regulation 8, Rule 8, Section 113)

This document is subject to the public notice, public comment, and public inspection requirements of District Regulations 2-2-405 and 2-2-406. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Oakley Generating Station and mailed to certain entities. The public inspection and comment period will be at least 30 days in duration and will start the date of such publication. Written comments on this document should be directed to:

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Air Quality Engineer II
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109
ktruesdell@baaqmd.gov

12. Glossary of Acronyms

AAQS	Ambient Air Quality Standard
ARB	Air Resource Board
BTU	British Thermal Unit
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
Cal ISO	California Independent System Operator
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CEM	Continuous Emission Monitor
CEQA	California Environmental Quality Act
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPUC	California Public Utilities Commission
CTG	Combustion Turbine Generator
EO/APCO	Executive Officer/Air Pollution Control Officer
EPA	Environmental Protection Agency
ERC	Emission Reduction Credit
FDOC	Final Determination of Compliance
FSNL	Full Speed No Load
GE	General Electric Company
GHG	Greenhouse Gases
GT	Gas Turbine
MW	Megawatt
NH_3	Ammonia
N_2	Nitrogen
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSR	New Source Review
O_2	Oxygen
OGS	Oakley Generating Station
LAER	Lowest Achievable Emissions Rate
LLC	Limited Liability Company
MMBtu	Million Btu
NAAQS	National Ambient Air Quality Standard
PAH	Polycyclic Aromatic Hydrocarbon
PDOC	Preliminary Determination of Compliance
PG&E	Pacific Gas & Electric Company
PM_{10}	Particulate Matter less than 10 Microns in Diameter
$PM_{2.5}$	Particulate Matter less than 2.5 Microns in Diameter
POC	Precursor Organic Compounds
ppmvd	Parts Per Million by Volume, Dry

PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
SCAQMD	South Coast Air Quality Management District
SNCR	Selective Non-catalytic Reduction
SCR	Selective Catalytic Reduction
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxides
TAC	Toxic Air Contaminant
TBACT	Toxics Best Available Control Technology
U.S. EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

Appendix A

Emission Calculations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to estimate and verify criteria pollutant and toxic air contaminant emissions submitted in the permit application. The criteria emission calculations were prepared by the applicant's consultant and are based on a combustion model. The District has verified these values using the calculations shown below. For the toxic air contaminants the District revised the calculation submitted by the applicant.

standard temperature[a]:	70^{o}F
standard pressure[a]:	14.7 psia
molar volume:	386.8 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8743 dscf/MM Btu
natural gas higher heating value:	1020 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 the gas turbines. 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	
	Combined-Cycle Gas Turbine	
	lb/MM Btu[c]	lb/hr[c]
Nitrogen Oxides (as NO_2)[a]	0.00722	15.52
Carbon Monoxide[b]	0.004395	9.45
Precursor Organic Compounds	0.00126	2.71
Particulate Matter (PM_{10})	0.0036	7.74
Sulfur Dioxide	0.00281	6.0
Sulfur Dioxide (Annual Average)	0.00070	1.5

[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 and abatement by the Selective Catalytic Reduction Systems with ammonia injection.
[b] based upon the permit condition emission limit of 2.0 ppmvd CO @ 15% O_2 that reflects abatement by oxidation catalysts.
[c] based upon firing rate of 2150 MMBtu/hour (100% Load, 34ºF)

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

The NO_x emissions from the combined-cycle gas turbines during normal operation will be 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.04 ppmv NO_x, dry @ 0% O_2

($7.04/10^6$)(1 lbmol/386.8 dscf)(46 lb NO_2/lbmol)(8743 dscf/MM Btu)

= **0.00732 lb NO_2/MM Btu**

Calculations shown below are based on emission factors submitted by the applicant.

The NO_x(as NO_2) mass emission rate based upon the maximum firing rate of the combined-cycle gas turbine is calculated as follows:

(0.00722 lb/MM Btu)(2150 MM Btu/hr) = **15.52 lb NO_x(as NO_2)/hr**

CARBON MONOXIDE EMISSION FACTORS

The CO emissions from the combined-cycle gas turbines during normal operation will be 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmv)(20.95 - 0)/(20.95 - 15) = 7.04 ppmv, dry @ 0% O_2

($7.04/10^6$)(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MM Btu)

= **0.00446 lb CO/MM Btu**

Calculations shown below are based on emission factors submitted by the applicant.

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

(0.004395 lb/MM Btu)(2150 MM Btu/hr) = **9.45 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

The POC emissions from the combined-cycle gas turbines during normal operation will be 1.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

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

($3.52/10^6$)(lbmol/386.8 dscf)(16 lb CH_4/lbmol)(8743 dscf/MM Btu)

= **0.00127 lb POC/MMBtu**

Calculations shown below are based on emission factors submitted by the applicant.

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

(0.00126 lb/MMBtu)(2150 MMBtu/hr) = **2.71 lb POC/hr**

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

The District has determined the BACT technology for the combined-cycle gas turbines corresponds to a PM_{10} emission rate of 0.0036 lb per MMBtu.

The PM mass emission rate based upon the maximum firing rate of the combined-cycle gas turbine is calculated as follows:

(0.0036 lb/MMBtu)(2150 MMBtu/hr) = **7.74 lb PM/hr**
(0.0036 lb/MMBtu)(35,397,277 MMBtu/year)/(2,000 lb/ton) = **63.715 TPY PM/year**

SULFUR DIOXIDE EMISSION FACTORS

The SO_2 emission factor is based upon annual average natural gas sulfur content of 0.25 grains per 100 scf and a higher heating value of 1020 Btu/scf.

The sulfur emission factor is calculated as follows:
SO_2 lb/hr

Natural Gas 1 grains of S/100 scf for Maximum Hourly

SO_2 = (1 gr S/100 scf)(lb S/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb SO_2/32 lb S)
= 0.00280 lb/MMBtu

Natural Gas 0.25 grains of S/100 scf for Annual Average

SO_2 = (0.25 gr/100 scf)(lb/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb SO_2/32 lb S)
= 0.00070 lb/MMBtu

Calculations shown below are based on emission factors submitted by the applicant.

Max Hourly SO_2

The corresponding SO_2 emission rate for the combined-cycle gas turbine firing:

(0.00281 lb SO_2/MM Btu)(2150 MM Btu/hr) = 6.0 lb/hr

Annual Average SO_2

The corresponding SO_2 emission rate for the combined-cycle gas turbine firing:

(0.00070 lb SO_2/MM Btu)(2150 MM Btu/hr) = 1.5 lb/hr

GE estimates for startups and shutdowns are summarized below by Radback Energy.

Oakley Generating Station 2x1

Startup Emissions Summary

Calculated Values		**Proposed Limits**
Hot Start		
Start Duration, minutes	14.0	30.0
Total per Start (per turbine)		
NO_x, lbs	22.0	22.0
CO, lbs	85.0	85.0
POC, lbs	31.0	31.0
PM_{10}, lbs	2.1	
SO_2, lbs (maximum)	0.9	
SO_2, lbs (annual average)	0.2	
Warm Start		
Start Duration, minutes	14.0	30.0
Total per Start (per turbine)		
NO_x, lbs	22.0	22.0
CO, lbs	85.0	85.0
POC, lbs	31.0	31.0
PM_{10}, lbs	2.1	
SO_2, lbs (maximum)	0.9	
SO_2, lbs (annual average)	0.2	
Cold Start		
Start Duration, minutes	45.0	90.0
Total per Start (per turbine)	5.0	
NO_x, lbs	96.0	96.0
CO, lbs	360.0	360.0
POC, lbs	67.0	67.0
PM_{10}, lbs	6.8	
SO_2, lbs (maximum)	2.9	
SO_2, lbs (annual average)	0.8	
Shutdown		
Shutdown Duration, minutes	30.0	60.0
Total per Shutdown (per turbine)		
NO_x, lbs	39.0	39.0
CO, lbs	140.0	140.0
POC, lbs	17.0	17.0
PM_{10}, lbs	4.5	
SO_2, lbs (maximum)	1.9	
SO_2, lbs (annual average)	0.5	

Maximum Hourly Emissions (per turbine)

Pollutant	Cold Startup (lb/event)[a]	Cold Startup (lb/hour)[b]	Hot/Warm Startup (lb/event)[c]	Hot/Warm Startup (lb/hour)[d]	Tuning (lb/event)[e]	Tuning (lb/hour)	Shutdown (lb/event)	Shutdown (lb/hour)
NO_x (as NO_2)	96.0	99.9	22.0	33.9	576	96.0	39	46.8
CO	360.0	362.4	85.0	92.2	2160	360.0	140	144.7
POC (as CH_4)	67.0	67.7	31.0	33.1	402	67.0	17	18.4

Maximum Daily Emissions for 2 turbines (without a Tuning Event)

Pollutant	(lb/day/turbine)	(lb/day/ 2 turbines)
NO_x (as NO_2)	488.1	976.2
CO	715.0	1430.0
POC (as CH_4)	145.7	291.3
$PM_{10}/PM_{2.5}$	185.8	371.5
SO_x (as SO_2)	144.0	288.0

NOx, CO, and POC are calculated by 1 cold start (45 min), 1 shut down (30 min), normal operation (22.75 hours)

PM and SOx are maximum pound per hour x 24 hours/day

Maximum Daily Emissions with a Tuning Event (2 turbines)

Pollutant	(lb/day/CT 1)	(lb/day/CT 2)	(lb/day/2 turbines)
NO_x (as NO_2)	971.0	488.1	1459.0
CO	2818.3	715.0	3533.3
POC (as CH_4)	531.4	145.7	677.0
$PM_{10}/PM_{2.5}$	185.8	185.8	371.5
SO_x (as SO_2)	144.0	144.0	288.0

CT 1 turbine: 1 tuning event (6 hours) + 1 cold start (45 min) + 1 shutdown (30 min) + normal operation (16.75 hours).

CT 2 turbine: 1 cold start (45 min) + 1 shutdown (30 min) + normal operation (22.75 hours).

Combustor tuning shall only be performed on one gas turbine per day.

Maximum Annual Emissions were calculated using three operating scenarios. The maximum emissions for each pollutant was used to establish the annual facility-wide emissions limits..

	Scenario 1	Scenario 2	Scenario 3
Combustion Turbines/HRSGs (per unit unless noted)			
Number of Turbines/HRSGs	2	2	2
Minimum Load Hours - Natural Gas	0	0	0
Base Load ISO Hours - Natural Gas	3657	3933	6924
Base Load Peak July Hours - Natural Gas	1500	1500	1500
Total Hot Starts - Natural Gas	275	260	51
Total Warm Starts - Natural Gas	0	51	0
Total Cold Starts - Natural Gas	25	1	1
Total Shutdowns - Natural Gas	300	312	52
Startup/Shutdown Hours	233	229	39
Total Hours of Operation	5390	5662	8463
Offline Hours	3370	3098	297
Annual Fuel Use, MMBtu (HHV) (all units)	22480757	23625816	35397277
Auxiliary Boiler			
Operating Hours	3603	3327	336
Total Starts	300	312	52
Total Shutdowns - Natural Gas	300	312	52
Evaporative Fluid Cooler			
Operating Hours	1500	1500	1500
Fire Pump			
Duration of Periodic Tests, mins	56	56	56
Frequency of Tests, tests/year	53	53	53
Load During Testing, %	1	1	1
Operating Hours	49	49	49
Annual Fuel Use, gals/yr	980	980	980

Pollutant	Factors (Estimated Annual Average)	Calculated Normal Operation (ISO)	Calculated Normal Operation (Peak July)	Hot/Warm Start (typical)	Cold Start (typical)	Shutdown (typical)
	ppmvd at 15% O2	lb/hour/turbine	lb/hour/turbine	lb/event	lb/event	lb/event
NO2	1.5	11.38	11.06	22	96	39
CO	1.0	4.62	4.49	85	360	140
POC	1.0	2.65	2.57	31	67	17
PM10	-	7.57	7.35	1.8	5.8	3.9
SO2 (annual)	0.25 grain/100scf	1.50	1.50	0.23	0.37	0.5
Ammonia	5.0	14.36	14.36			
Time (minutes)				14	45	30

Notes:
Emission rates and concentrations estimated by Radback Energy
BAAQMD adjusted PM emissions based on 0.0036 lb/MMBtu

Maximum Annual Regulated Air Pollutant emission calculations submitted by the Applicant were verified below. Proposed permit limits are calculated by the Applicant and differences can be attributed to rounding.

Scenario 1	2 turbines				Boiler	Boiler	Fire Pump Engine	Evaporative Fluid	Oil/Water	**Scenario 1**
	Normal Operation	Hot/Warm Starts	Cold Starts	Shutdown	Normal Operation	Startup & Shutdown		Cooler	Separator	**Emissions**
Pollutant	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	**TPY**
NO2	58.20	6.05	2.40	11.70	0.76	0.24	0.06			**79.4**
CO	23.62	23.38	9.00	42.00	0.66	0.21	0.01			**98.9**
POC	13.53	8.53	1.68	5.10	0.19	0.06	0.00		0.11	**29.2**
PM10	38.71	0.50	0.15	1.16	0.64	0.07	0.00	0.10		**41.3**
SO2	7.74	0.06	0.01	0.15	0.25	0.03	0.00			**8.2**
	2 turbines				Boiler	Boiler	Fire Pump Engine	Evaporative Fluid	Oil/Water	**Scenario 2**
Scenario 2	Normal Operation	Hot/Warm Starts	Cold Starts	Shutdown	Normal Operation	Startup & Shutdown		Cooler	Separator	**Emissions**
Pollutant	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	**TPY**
NO2	61.34	6.84	0.10	12.17	0.70	0.25	0.06			**81.5**
CO	24.90	26.44	0.36	43.68	0.61	0.22	0.01			**96.2**
POC	14.26	9.64	0.07	5.30	0.18	0.06	0.00		0.11	**29.6**
PM10	40.79	0.56	0.01	1.21	0.59	0.07	0.00	0.10		**43.3**
SO2	8.15	0.07	0.00	0.16	0.23	0.03	0.00			**8.6**
	2 turbines				Boiler	Boiler	Fire Pump Engine	Evaporative Fluid	Oil/Water	**Scenario 3**
Scenario 3	Normal Operation	Hot/Warm Starts	Cold Starts	Shutdown	Normal Operation	Startup & Shutdown		Cooler	Separator	**Emissions**
Pollutant	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	**TPY**
NO2	95.38	1.12	0.10	2.03	0.07	0.04	0.06			**98.8**
CO	38.71	4.34	0.36	7.28	0.06	0.04	0.01			**50.8**
POC	22.17	1.58	0.07	0.88	0.02	0.01	0.00		0.11	**24.8**
PM10	63.43	0.09	0.01	0.20	0.06	0.01	0.00	0.10		**63.9**
SO2	12.64	0.01	0.00	0.03	0.02	0.00	0.00			**12.7**

Maximum Toxic Air Contaminant Emissions from Normal Operation of the Gas Turbines

Toxic Air Contaminant	EF lb/MMBtu	Per Turbine EF lb/mmscf	Per Turbine Firing Rate mmscf/hour	Firing Rate mmscf/year	Per Turbine lb/hour	Per Turbine lb/year	Total CT lb/hour	Total CT lb/year	Total CT TPY
1,3-Butadiene	1.24E-07	1.27E-04	2.104	17,317.65	2.67E-04	2.20E+00	5.34E-04	4.40E+00	2.20E-03
Acetaldehyde	1.34E-04	1.37E-01			2.88E-01	2.37E+03	5.76E-01	4.75E+03	2.37E+00
Acrolein	1.85E-05	1.89E-02			3.98E-02	3.27E+02	7.95E-02	6.55E+02	3.27E-01
Ammonia	6.82E-03	6.97E+00			1.47E+01	1.21E+05	2.93E+01	2.41E+05	1.21E+02
Benzene	1.30E-05	1.33E-02			2.80E-02	2.30E+02	5.60E-02	4.61E+02	2.30E-01
Benzo(a)anthracene	*2.21E-08*	*2.26E-05*			*4.76E-05*	*3.91E-01*	*9.51E-05*	*7.83E-01*	*3.91E-04*
Benzo(a)pyrene	*1.36E-08*	*1.39E-05*			*2.92E-05*	*2.41E-01*	*5.85E-05*	*4.81E-01*	*2.41E-04*
Benzo(b)fluoranthene	*1.11E-08*	*1.13E-05*			*2.38E-05*	*1.96E-01*	*4.76E-05*	*3.91E-01*	*1.96E-04*
Benzo(k)fluoranthene	*1.08E-08*	*1.10E-05*			*2.31E-05*	*1.90E-01*	*4.63E-05*	*3.81E-01*	*1.90E-04*
Chrysene	*2.47E-08*	*2.52E-05*			*5.30E-05*	*4.36E-01*	*1.06E-04*	*8.73E-01*	*4.36E-04*
Dibenz(a,h)anthracene	*2.30E-08*	*2.35E-05*			*4.94E-05*	*4.07E-01*	*9.89E-05*	*8.14E-01*	*4.07E-04*
Ethylbenzene	1.75E-05	1.79E-02			3.77E-02	3.10E+02	7.53E-02	6.20E+02	3.10E-01
Formaldehyde	4.49E-04	4.59E-01			9.65E-01	7.94E+03	1.93E+00	1.59E+04	7.94E+00
Hexane	2.53E-04	2.59E-01			5.45E-01	4.49E+03	1.09E+00	8.97E+03	4.49E+00
Indeno(1,2,3-cd)pyrene	*2.30E-08*	*2.35E-05*			*4.94E-05*	*4.07E-01*	*9.89E-05*	*8.14E-01*	*4.07E-04*
Naphthalene	1.62E-06	1.66E-03			3.49E-03	2.87E+01	6.99E-03	5.75E+01	2.87E-02
Propylene	7.54E-04	7.71E-01			1.62E+00	1.34E+04	3.24E+00	2.67E+04	1.34E+01
Propylene Oxide	4.68E-05	4.78E-02			1.01E-01	8.28E+02	2.01E-01	1.66E+03	8.28E-01
Toluene	6.95E-05	7.10E-02			1.49E-01	1.23E+03	2.99E-01	2.46E+03	1.23E+00
Xylene (Total)	2.55E-05	2.61E-02			5.49E-02	4.52E+02	1.10E-01	9.04E+02	4.52E-01
Sulfuric Acid Mist (H2SO4) - short term	1.42E-03	1.45E+00			3.06E+00		6.12E+00		
Sulfuric Acid Mist (H2SO4) - annual average	3.56E-04	3.64E-01				6.30E+03		1.26E+04	6.30E+00
Benzo(a)pyrene equivalents	4.47E-08	4.57E-05			9.61E-05	7.91E-01	1.92E-04	1.58E+00	7.91E-04
Specified PAHs					0.00	2.27	0.00	4.54	0.00

Formaldehyde emissions reflect 50% destruction due to oxidation catalyst.

	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

Ammonia lb/MMBtu = ppmvd x 10^-06 x 1/molar volume x MW x Fd x 20.9/(20.9 - %O2)

ppm =	5	ppmvd @15%O2 limit
molar volume =	386.8	dscf/lbmol @ 14.696 psia, 70 deg. F
MW =	17.03	molecular weight, lb/lb-mol
Fd =	8743	dscf/MMBtu for Natural Gas @ 70 deg. F
O2 in exhaust air	15	%

Ammonia lb/MMBtu = 5.0E-06 ft3 of NH3/ft3 stack gas x 1/386.8 dscf/lb-mol x 17.03 lb/lb-mol x 8743 dscf/MMBtu x 20.9/(20.9 - 15)

Ammonia lb/MMBtu =	6.82E-03
Ammonia lb/mmscf =	6.97E+00

Annual Toxic Air Contaminant Emissions
Scenario 1
2 turbines

Toxic Air Contaminant	Normal Operation lb/year	Hot Starts lb/year	Warm Starts lb/year	Cold Starts lb/year	Shutdowns lb/year	Tuning lb/year	Scenario 1 Emissions lb/year
1,3-Butadiene	2.70E+00	2.40E-02	0.00E+00	7.01E-03	1.60E-01	8.55E-03	2.90E+00
Acetaldehyde	2.91E+03	2.42E+02	0.00E+00	7.07E+01	1.73E+02	8.62E+01	3.48E+03
Acrolein	4.02E+02	1.30E+01	0.00E+00	3.81E+00	2.39E+01	4.64E+00	4.47E+02
Ammonia	1.48E+05	1.32E+03	0.00E+00	3.85E+02	8.80E+03	4.69E+02	1.59E+05
Benzene	2.83E+02	4.84E+00	0.00E+00	1.41E+00	1.68E+01	1.72E+00	3.07E+02
Benzo(a)anthracene	4.80E-01	4.27E-03	0.00E+00	1.25E-03	2.85E-02	1.52E-03	5.16E-01
Benzo(a)pyrene	2.95E-01	2.63E-03	0.00E+00	7.68E-04	1.75E-02	9.36E-04	3.17E-01
Benzo(b)fluoranthene	2.40E-01	2.14E-03	0.00E+00	6.24E-04	1.43E-02	7.61E-04	2.58E-01
Benzo(k)fluoranthene	2.34E-01	2.08E-03	0.00E+00	6.08E-04	1.39E-02	7.41E-04	2.51E-01
Chrysene	5.35E-01	4.76E-03	0.00E+00	1.39E-03	3.18E-02	1.70E-03	5.75E-01
Dibenz(a,h)anthracene	4.99E-01	4.44E-03	0.00E+00	1.30E-03	2.97E-02	1.58E-03	5.36E-01
Ethylbenzene	3.80E+02	6.16E+00	0.00E+00	1.80E+00	2.26E+01	2.19E+00	4.13E+02
Formaldehyde	9.74E+03	8.75E+02	0.00E+00	2.56E+02	5.79E+02	3.12E+02	1.18E+04
Hexane	5.50E+03	4.90E+01	0.00E+00	1.43E+01	3.27E+02	1.74E+01	5.91E+03
Indeno(1,2,3-cd)pyrene	4.99E-01	4.44E-03	0.00E+00	1.30E-03	2.97E-02	1.58E-03	5.36E-01
Naphthalene	3.53E+01	3.14E-01	0.00E+00	9.17E-02	2.10E+00	1.12E-01	3.79E+01
Propylene	1.64E+04	1.46E+02	0.00E+00	4.26E+01	9.73E+02	5.19E+01	1.76E+04
Propylene Oxide	1.02E+03	9.03E+00	0.00E+00	2.64E+00	6.03E+01	3.22E+00	1.09E+03
Toluene	1.51E+03	1.86E+01	0.00E+00	5.42E+00	8.96E+01	6.61E+00	1.63E+03
Xylene (Total)	5.54E+02	4.93E+00	0.00E+00	1.44E+00	3.29E+01	1.76E+00	5.96E+02
Sulfuric Acid Mist (H2SO4)	7.73E+03	2.75E+02	0.00E+00	8.04E+01	1.84E+03	9.80E+01	1.00E+04
Benzo(a)pyrene equivalents	9.70E-01	8.63E-03	0.00E+00	2.52E-03	5.77E-02	3.07E-03	1.04E+00

Annual Toxic Air Contaminant Emissions

Toxic Air Contaminant	Scenario 2 2 turbines Normal Operation lb/year	Hot Starts lb/year	Warm Starts lb/year	Cold Starts lb/year	Shutdowns lb/year	Tuning lb/year	Scenario 2 Emissions lb/year
1,3-Butadiene	2.39E+00	2.27E-02	4.45E-03	2.81E-04	5.84E-02	8.55E-03	2.49E+00
Acetaldehyde	2.58E+03	2.29E+02	4.49E+01	2.83E+00	5.88E+02	8.62E+01	3.53E+03
Acrolein	3.56E+02	1.23E+01	2.42E+00	1.52E-01	3.17E+01	4.64E+00	4.08E+02
Ammonia	1.31E+05	1.25E+03	2.44E+02	1.54E+01	3.20E+03	4.69E+02	1.37E+05
Benzene	2.51E+02	4.57E+00	8.97E-01	5.66E-02	1.18E+01	1.72E+00	2.70E+02
Benzo(a)anthracene	4.26E-01	4.04E-03	7.92E-04	4.99E-05	1.04E-02	1.52E-03	4.43E-01
Benzo(a)pyrene	2.62E-01	2.48E-03	4.87E-04	3.07E-05	6.39E-03	9.36E-04	2.72E-01
Benzo(b)fluoranthene	2.13E-01	2.02E-03	3.96E-04	2.50E-05	5.19E-03	7.61E-04	2.21E-01
Benzo(k)fluoranthene	2.07E-01	1.97E-03	3.86E-04	2.43E-05	5.05E-03	7.41E-04	2.16E-01
Chrysene	4.75E-01	4.50E-03	8.83E-04	5.57E-05	1.16E-02	1.70E-03	4.94E-01
Dibenz(a,h)anthracene	4.43E-01	4.20E-03	8.24E-04	5.19E-05	1.08E-02	1.58E-03	4.61E-01
Ethylbenzene	3.37E+02	5.83E+00	1.14E+00	7.20E-02	1.50E+01	2.19E+00	3.62E+02
Formaldehyde	8.64E+03	8.27E+02	1.62E+02	1.02E+01	2.13E+03	3.12E+02	1.21E+04
Hexane	4.88E+03	4.63E+01	9.08E+00	5.72E-01	1.19E+02	1.74E+01	5.08E+03
Indeno(1,2,3-cd)pyrene	4.43E-01	4.20E-03	8.24E-04	5.19E-05	1.08E-02	1.58E-03	4.61E-01
Naphthalene	3.13E+01	2.97E-01	5.82E-02	3.67E-03	7.63E-01	1.12E-01	3.25E+01
Propylene	1.45E+04	1.38E+02	2.70E+01	1.70E+00	3.54E+02	5.19E+01	1.51E+04
Propylene Oxide	9.01E+02	8.54E+00	1.68E+00	1.06E-01	2.20E+01	3.22E+00	9.37E+02
Toluene	1.34E+03	1.75E+01	3.44E+00	2.17E-01	4.51E+01	6.61E+00	1.41E+03
Xylene (Total)	4.92E+02	4.66E+00	9.15E-01	5.77E-02	1.20E+01	1.76E+00	5.11E+02
Sulfuric Acid Mist (H2SO4)	6.86E+03	2.60E+02	5.10E+01	3.21E+00	6.69E+02	9.80E+01	7.94E+03
Benzo(a)pyrene equivalents	8.61E-01	8.16E-03	1.60E-03	1.01E-04	2.10E-02	3.07E-03	8.95E-01

Annual Toxic Air Contaminants Scenario 3									Worst Case Max. Annual
	2 turbines						Scenario 3	Full Load	
	Normal Operation	Hot Starts	Warm Starts	Cold Starts	Shutdowns	Tuning	Emissions from 2 turbines	Emissions from 2 turbines	Emissions per turbine
Toxic Air Contaminant	lb/year	lb/year	lb/year	lb/year	lb/year	lb/year	lb/year	lb/year	lb/year
1,3-Butadiene	4.38E+00	4.45E-03	0.00E+00	2.81E-04	9.73E-03	8.55E-03	**4.3987E+00**	4.3987E+00	**2.1993E+00**
Acetaldehyde	4.72E+03	4.49E+01	0.00E+00	2.83E+00	9.80E+01	8.62E+01	**4.9521E+03**	4.7450E+03	**2.4761E+03**
Acrolein	6.51E+02	2.42E+00	0.00E+00	1.52E-01	5.28E+00	4.64E+00	**6.6367E+02**	6.5461E+02	**3.3183E+02**
Ammonia	2.40E+05	2.44E+02	0.00E+00	1.54E+01	5.34E+02	4.69E+02	**2.4134E+05**	2.4134E+05	**1.2067E+05**
Benzene	4.58E+02	8.97E-01	0.00E+00	5.66E-02	1.96E+00	1.72E+00	**4.6288E+02**	4.6065E+02	**2.3144E+02**
Benzo(a)anthracene	7.79E-01	7.92E-04	0.00E+00	4.99E-05	1.73E-03	1.52E-03	**7.8276E-01**	7.8276E-01	**3.9138E-01**
Benzo(a)pyrene	4.79E-01	4.87E-04	0.00E+00	3.07E-05	1.06E-03	9.36E-04	**4.8143E-01**	4.8143E-01	**2.4072E-01**
Benzo(b)fluoranthene	3.89E-01	3.96E-04	0.00E+00	2.50E-05	8.65E-04	7.61E-04	**3.9138E-01**	3.9138E-01	**1.9569E-01**
Benzo(k)fluoranthene	3.79E-01	3.86E-04	0.00E+00	2.43E-05	8.42E-04	7.41E-04	**3.8099E-01**	3.8099E-01	**1.9049E-01**
Chrysene	8.68E-01	8.83E-04	0.00E+00	5.57E-05	1.93E-03	1.70E-03	**8.7281E-01**	8.7281E-01	**4.3640E-01**
Dibenz(a,h)anthracene	8.10E-01	8.24E-04	0.00E+00	5.19E-05	1.80E-03	1.58E-03	**8.1393E-01**	8.1393E-01	**4.0696E-01**
Ethylbenzene	6.17E+02	1.14E+00	0.00E+00	7.20E-02	2.50E+00	2.19E+00	**6.2264E+02**	6.1997E+02	**3.1132E+02**
Formaldehyde	1.58E+04	1.62E+02	0.00E+00	1.02E+01	3.55E+02	3.12E+02	**1.6636E+04**	1.5880E+04	**8.3180E+03**
Hexane	8.92E+03	9.08E+00	0.00E+00	5.72E-01	1.98E+01	1.74E+01	**8.9705E+03**	8.9705E+03	**4.4853E+03**
Indeno(1,2,3-cd)pyrene	8.10E-01	8.24E-04	0.00E+00	5.19E-05	1.80E-03	1.58E-03	**8.1393E-01**	8.1393E-01	**4.0696E-01**
Naphthalene	5.72E+01	5.82E-02	0.00E+00	3.67E-03	1.27E-01	1.12E-01	**5.7495E+01**	5.7495E+01	**2.8747E+01**
Propylene	2.66E+04	2.70E+01	0.00E+00	1.70E+00	5.90E+01	5.19E+01	**2.6704E+04**	2.6704E+04	**1.3352E+04**
Propylene Oxide	1.65E+03	1.68E+00	0.00E+00	1.06E-01	3.66E+00	3.22E+00	**1.6556E+03**	1.6556E+03	**8.2778E+02**
Toluene	2.45E+03	3.44E+00	0.00E+00	2.17E-01	7.52E+00	6.61E+00	**2.4640E+03**	2.4591E+03	**1.2320E+03**
Xylene (Total)	8.99E+02	9.15E-01	0.00E+00	5.77E-02	2.00E+00	1.76E+00	**9.0398E+02**	9.0398E+02	**4.5199E+02**
Sulfuric Acid Mist (H2SO4)	1.25E+04	5.10E+01	0.00E+00	3.21E+00	1.11E+02	9.80E+01	**1.2795E+04**	1.2598E+04	**6.3976E+03**
Benzo(a)pyrene equivalents	1.57E+00	1.60E-03	0.00E+00	1.01E-04	3.50E-03	3.07E-03	**1.5817E+00**	1.5817E+00	**7.9085E-01**
Specified PAHs							**4.5372E+00**	4.5372E+00	**2.2686E+00**

Toxic Air Contaminant Emissions from Startup/Shutdown of Gas Turbines

Toxic Air Contaminant	CATEF EF lb/mmscf		SDAPCD EF lb/mmscf	Startup/Shutdown EF lb/mmscf	Startup/Shutdown EF Source
1,3-Butadiene	1.27E-04			1.27E-04	CATEF
Acetaldehyde	1.37E-01		1.28E+00	1.28E+00	SDAPCD
Acrolein	1.89E-02		6.89E-02	6.89E-02	SDAPCD
Ammonia				6.97E+00	Permit limit
Benzene	1.33E-02		2.56E-02	2.56E-02	SDAPCD
Benzo(a)anthracene	*2.26E-05*	*ND*	*2.25E-05*	2.26E-05	CATEF
Benzo(a)pyrene	*1.39E-05*	*ND*	*1.39E-05*	1.39E-05	CATEF
Benzo(b)fluoranthene	*1.13E-05*			1.13E-05	CATEF
Benzo(k)fluoranthene	*1.10E-05*			1.10E-05	CATEF
Chrysene	*2.52E-05*	*ND*	*2.25E-05*	2.52E-05	CATEF
Dibenz(a,h)anthracene	*2.35E-05*	*ND*	*2.25E-05*	2.35E-05	CATEF
Ethylbenzene	1.79E-02		3.26E-02	3.26E-02	SDAPCD
Formaldehyde	9.17E-01		4.63E+00	4.63E+00	SDAPCD
Hexane	2.59E-01			2.59E-01	CATEF
Indeno(1,2,3-cd)pyrene	*2.35E-05*	*ND*	*2.25E-05*	2.35E-05	CATEF
Naphthalene	1.66E-03		1.04E-03	1.66E-03	CATEF
Propylene	7.71E-01			7.71E-01	CATEF
Propylene Oxide	4.78E-02			4.78E-02	CATEF
Toluene	7.10E-02		9.82E-02	9.82E-02	SDAPCD
Xylene (Total)	2.61E-02		3.48E-03	2.61E-02	CATEF
Sulfuric Acid Mist (H2SO4)				1.45E+00	Permit limit of SO2
Benzo(a)pyrene equivalents (calculated)	4.57E-05		4.23E-05	4.57E-05	CATEF

	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

Event	Fuel Usage mmscf	Minimum Time minutes	Fuel Usage MMBtu
Cold Startup	1.1046	45	1128.9
Warm/Hot Startup	0.3437	14	351.2
Shutdown	0.7364	30	752.6
Tuning	16.8320	480	17202.3

CATEF = California Air Toxics Emission Factors Database maintained by the California Air Resources Board
SDAPCD = San Diego Air Pollution Control District. Emission factors developed from source testing of Palomar GE Frame 7FA turbine during the 1st hour of a cold startup. Data from Carlsbad Energy Center Final Determination of Compliance, Appendix B, August 4, 2009, SDAPCD
ND = Non Detect from SDAPCD, Emission Factor is one half of the dectection limit.
Natural Gas Higher Heating Value = 1022 Btu/scf
Startup Emission Factors are the highest value of the CATEF of SDAPCD Emission Factors
Fuel Usage during startup/shutdown assumed to be 70% of baseload rate
Fuel Usage during commissioning assumed to be 100% of baseload rate

Toxic Air Contaminant Emissions from Startup/Shutdown/Tuning of Gas Turbines

Toxic Air Contaminant	45 min Cold Startup balance Normal Emissions lb/hour	14 min Warm/Hot Startup balance Normal Emissions lb/hour	30 min Shutdown balance Normal Emissions lb/hour	14 min Warm/Hot Startup 30 min Shutdown balance Normal lb/hour	Tuning lb/hour
1,3-Butadiene	2.07E-04	2.49E-04	2.27E-04	2.08E-04	2.67E-04
Acetaldehyde	1.49E+00	6.61E-01	1.09E+00	1.46E+00	2.69E+00
Acrolein	8.60E-02	5.42E-02	7.06E-02	8.50E-02	1.45E-01
Ammonia	1.14E+01	1.36E+01	1.25E+01	1.14E+01	1.47E+01
Benzene	3.53E-02	3.03E-02	3.28E-02	3.51E-02	5.39E-02
Benzo(a)anthracene	3.69E-05	4.42E-05	4.04E-05	3.71E-05	4.76E-05
Benzo(a)pyrene	2.27E-05	2.72E-05	2.49E-05	2.28E-05	2.92E-05
Benzo(b)fluoranthene	1.84E-05	2.21E-05	2.02E-05	1.85E-05	2.38E-05
Benzo(k)fluoranthene	1.79E-05	2.15E-05	1.97E-05	1.81E-05	2.31E-05
Chrysene	4.11E-05	4.93E-05	4.51E-05	4.14E-05	5.30E-05
Dibenz(a,h)anthracene	3.83E-05	4.60E-05	4.20E-05	3.86E-05	4.94E-05
Ethylbenzene	4.54E-02	4.01E-02	4.28E-02	4.53E-02	6.86E-02
Formaldehyde	5.36E+00	2.33E+00	3.89E+00	5.26E+00	9.74E+00
Hexane	4.22E-01	5.07E-01	4.63E-01	4.25E-01	5.45E-01
Indeno(1,2,3-cd)pyrene	3.83E-05	4.60E-05	4.20E-05	3.86E-05	4.94E-05
Naphthalene	2.71E-03	3.25E-03	2.97E-03	2.72E-03	3.49E-03
Propylene	1.26E+00	1.51E+00	1.38E+00	1.27E+00	1.62E+00
Propylene Oxide	7.79E-02	9.35E-02	8.55E-02	7.84E-02	1.01E-01
Toluene	1.46E-01	1.48E-01	1.47E-01	1.46E-01	2.07E-01
Xylene (Total)	4.26E-02	5.11E-02	4.67E-02	4.28E-02	5.49E-02
Sulfuric Acid Mist (H2SO4)	2.37E+00	2.85E+00	2.60E+00	2.39E+00	3.06E+00
Benzo(a)pyrene equivalents (c	7.45E-05	8.94E-05	8.17E-05	7.49E-05	9.61E-05

Toxic Air Contaminant Emissions from Startup/Shutdown of Gas Turbines

Toxic Air Contaminant	**Worst Case Maximum Hourly Emissions per Turbine No Tuning lb/hour**	**Worst Case Maximum Hourly Emissions per Turbine**	**Worst Case Maximum Hourly Emissions per Turbine Including Tuning lb/hour**	**Worst Case Maximum Hourly Emissions per Turbine**
1,3-Butadiene	**2.67E-04**	Normal Operation	**2.67E-04**	Normal Operation
Acetaldehyde	**1.49E+00**	45 min Cold Startup balance Normal	**2.69E+00**	Tuning
Acrolein	**8.60E-02**	45 min Cold Startup balance Normal	**1.45E-01**	Tuning
Ammonia	**1.47E+01**	Normal Operation	**1.47E+01**	Normal Operation
Benzene	**3.53E-02**	45 min Cold Startup balance Normal	**5.39E-02**	Tuning
Benzo(a)anthracene	**4.76E-05**	Normal Operation	**4.76E-05**	Normal Operation
Benzo(a)pyrene	**2.92E-05**	Normal Operation	**2.92E-05**	Normal Operation
Benzo(b)fluoranthene	**2.38E-05**	Normal Operation	**2.38E-05**	Normal Operation
Benzo(k)fluoranthene	**2.31E-05**	Normal Operation	**2.31E-05**	Normal Operation
Chrysene	**5.30E-05**	Normal Operation	**5.30E-05**	Normal Operation
Dibenz(a,h)anthracene	**4.94E-05**	Normal Operation	**4.94E-05**	Normal Operation
Ethylbenzene	**4.54E-02**	45 min Cold Startup balance Normal	**6.86E-02**	Tuning
Formaldehyde	**5.36E+00**	45 min Cold Startup balance Normal	**9.74E+00**	Tuning
Hexane	**5.45E-01**	Normal Operation	**5.45E-01**	Normal Operation
Indeno(1,2,3-cd)pyrene	**4.94E-05**	Normal Operation	**4.94E-05**	Normal Operation
Naphthalene	**3.49E-03**	Normal Operation	**3.49E-03**	Normal Operation
Propylene	**1.62E+00**	Normal Operation	**1.62E+00**	Normal Operation
Propylene Oxide	**1.01E-01**	Normal Operation	**1.01E-01**	Normal Operation
Toluene	**1.49E-01**	Normal Operation	**2.07E-01**	Tuning
Xylene (Total)	**5.49E-02**	Normal Operation	**5.49E-02**	Normal Operation
Sulfuric Acid Mist (H2SO4)	**3.06E+00**	Normal Operation	**3.06E+00**	Normal Operation
Benzo(a)pyrene equivalents (calculated)	**9.61E-05**	Normal Operation	**9.61E-05**	Normal Operation

CATEF Gas Turbine TAC Emission Factors

ID	System Type	Material Type	SCC	APC Device	Other Description	CAS	Substance	Max Emission factor	Mean	Median	Unit
4544	Turbine	Natural gas	2E+07	None	None	106-99-0	1,3-Butadiene	1.33E-04	1.27E-04	1.24E-04	lbs/MMcf
4569	Turbine	Natural gas	2E+07	None	None	75-07-0	Acetaldehyde	5.11E-01	1.37E-01	5.38E-02	lbs/MMcf
4574	Turbine	Natural gas	2E+07	None	None	107-02-8	Acrolein	6.93E-02	1.89E-02	1.09E-02	lbs/MMcf
4587	Turbine	Natural gas	2E+07	None	None	71-43-2	Benzene	4.72E-02	1.33E-02	1.01E-02	lbs/MMcf
4594	Turbine	Natural gas	2E+07	None	None	56-55-6	Benzo(a)anthracene	1.34E-04	2.26E-05	3.61E-06	lbs/MMcf
4599	Turbine	Natural gas	2E+07	None	None	50-32-8	Benzo(a)pyrene	9.16E-05	1.39E-05	2.57E-06	lbs/MMcf
4604	Turbine	Natural gas	2E+07	None	None	205-99-2	Benzo(b)fluoranthene	6.72E-05	1.13E-05	2.87E-06	lbs/MMcf
4619	Turbine	Natural gas	2E+07	None	None	207-08-9	Benzo(k)fluoranthene	6.72E-05	1.10E-05	2.87E-06	lbs/MMcf
4624	Turbine	Natural gas	2E+07	None	None	218-01-9	Chrysene	1.50E-04	2.52E-05	4.99E-06	lbs/MMcf
4629	Turbine	Natural gas	2E+07	None	None	53-70-3	Dibenz(a,h)anthracene	1.34E-04	2.35E-05	3.03E-06	lbs/MMcf
4634	Turbine	Natural gas	2E+07	None	None	100-41-4	Ethylbenzene	5.70E-02	1.79E-02	9.74E-03	lbs/MMcf
4649	Turbine	Natural gas	2E+07	None	None	50-00-0	Formaldehyde	6.87E+00	9.17E-01	1.12E-01	lbs/MMcf
4654	Turbine	Natural gas	2E+07	None	None	110-54-3	Hexane	3.82E-01	2.59E-01	2.19E-01	lbs/MMcf
4659	Turbine	Natural gas	2E+07	None	None	193-39-5	Indeno(1,2,3-cd)pyrene	1.34E-04	2.35E-05	2.87E-06	lbs/MMcf
4664	Turbine	Natural gas	2E+07	None	None	91-20-3	Naphthalene	7.88E-03	1.66E-03	9.26E-04	lbs/MMcf
4679	Turbine	Natural gas	2E+07	None	None	115-07-1	Propylene	2.00E+00	7.71E-01	5.71E-01	lbs/MMcf
4684	Turbine	Natural gas	2E+07	None	None	75-56-9	Propylene Oxide	5.87E-02	4.78E-02	4.48E-02	lbs/MMcf
4694	Turbine	Natural gas	2E+07	None	None	108-88-3	Toluene	1.68E-01	7.10E-02	5.91E-02	lbs/MMcf
4709	Turbine	Natural gas	2E+07	None	None	1330-20-7	Xylene (Total)	6.26E-02	2.61E-02	1.93E-02	lbs/MMcf

Table A-2 summarizes the regulated air pollutant emission factors submitted by the applicant that were used to calculate mass emission rates for the auxiliary boiler. 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-2
CONTROLLED REGULATED AIR POLLUTANT EMISSION FACTORS FOR AUXILIARY BOILER

Pollutant	Source	
	Auxiliary Boiler	
	lb/MM Btu [c]	lb/hr [c]
Nitrogen Oxides (as NO_2)[a]	0.0083	0.42
Carbon Monoxide[b]	0.0073	0.37
Precursor Organic Compounds	0.0022	0.11
Particulate Matter (PM_{10})	0.0069	0.35
Sulfur Dioxide	0.0028	0.14

[a] Based upon stack concentration of 7.0 ppmvd NO_x @ 3% O_2 that reflects the use of ultra-low-NO_x burners and flue gas recirculation. NO_x concentration will be monitored by continuous emission monitors.
[b] Based upon stack concentration of 10.0 ppmvd CO @ 3% O_2. Applicant may use vendor guarantee of 10.0 ppm CO or may use an oxidation catalyst. CO concentration will be monitored by continuous emission monitors.
[c] Based upon firing rate of 50.6 MMBtu/hour

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

The NO_x emissions from the auxiliary boiler during normal operation will be 7.0 ppmv, dry @ 3% O_2. This concentration is converted to a mass emission factor as follows:

(7.0 ppmvd)(20.95 - 0)/(20.95 - 3) = 8.17 ppmv NO_x, dry @ 0% O_2

($8.17/10^6$)(1 lbmol/386.8 dscf)(46 lb NO_2/lbmol)(8743 dscf/MM Btu) = **0.0085 lb NO_2/MM Btu**

Calculations shown below are based on emission factors submitted by the applicant.

The NO_x(as NO_2) mass emission rate based upon the maximum firing rate of the auxiliary boiler is calculated as follows:

(0.0083 lb/MM Btu)(50.6 MM Btu/hr) = **0.42 lb NO_x(as NO_2)/hr**

CARBON MONOXIDE EMISSION FACTORS

The CO emissions from the auxiliary boiler during normal operation will be 10.0 ppmv, dry @ 3% O_2. This concentration is converted to a mass emission factor as follows:

$(10.0 \text{ ppmv})(20.95 - 0)/(20.95 - 3) = 11.67$ ppmv, dry @ 0% O_2

$(11.67/10^6)$(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MM Btu) = **0.00739 lb CO/MM Btu**

Calculations shown below are based on emission factors submitted by the applicant.

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

(0.0073 lb/MM Btu)(50.6 MM Btu/hr) = **0.37 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

The POC emissions from the auxiliary boiler during normal operation will be 5.0 ppmv, dry @ 3% O_2. This concentration is converted to a mass emission factor as follows:

$(5.0 \text{ ppmv})(20.95 - 0)/(20.95 - 3) = 5.36$ ppmv, dry @ 0% O_2

$(5.36/10^6)$(lbmol/386.8 dscf)(16 lb CH_4/lbmol)(8743 dscf/MM Btu) = **0.0019 lb POC/MMBtu**

Calculations shown below are based on emission factors submitted by the applicant.

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

(0.0022 lb/MM Btu)(50.6 MM Btu/hr) = **0.11 lb POC/hr**

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

The applicant has estimated PM emissions to be 0.007 lb/MMBtu.

(0.007 lb/MMBtu)(50.6 MMBtu/hr) = **0.35 lb PM_{10}/hr**

SULFUR DIOXIDE EMISSION FACTORS

The sulfur emission factor is calculated as follows:

Natural Gas 1 grains of S/100 scf for Maximum Hourly

SO_2 = (1 gr S/100 scf)(lb S/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb SO_2/32 lb S) = 0.00280 lb/MMBtu

Calculations shown below are based on emission factors submitted by the applicant.

Max Hourly SO_2

The corresponding SO_2 emission rate for the combined-cycle gas turbine firing:

(0.0028 lb SO_2/MM Btu)(50.6 MM Btu/hr) = **0.14 lb/hr**

Toxic Air Contaminants from the auxiliary boiler were adjusted by the District in accordance with the memo from dated September 7, 2005 from Brian Bateman to the Engineering Division Staff regarding Emission Factors for Toxic Air Contaminants from Miscellaneous Natural Gas Combustion Sources (included at the end of this Appendix).

TABLE A-3
TOXIC AIR CONTAMINANT EMISSIONS FROM AUXILIARY BOILER

Toxic Air Contaminant	Factor	Factor	Emissions		Trigger Levels	
	lb/MMBTU	lb/mmscf	lb/hr	lb/yr	lb/hr	lb/yr
Benzene	2.06E-06	2.10E-03	1.04E-04	0.45	2.9E+00	3.8E+00
Formaldehyde	7.35E-05	7.50E-02	3.71E-03	16.04	1.2E-01	1.8E+01
Sulfuric Acid	1.42E-03	1.45E+00	7.20E-02	0.16	2.6E-01	3.9E+01
Toluene	3.33E-06	3.40E-03	1.65E-07	0.73	8.2E+01	1.2E+04

Emergency Diesel-driven Fire Pump						
Manufacturer	Clarke					
Model	JW6H-UFAD80					
CARB-certified Tier 3	U-R-004-0369					
Operating Hours Per Year (hr/yr)	49					
From Manufacturer's Data						
Fuel Consumption Rate (gal/hr)	20		Calc MMBtu/hr =	2.78		
Brake Horsepower of Engine (HP)	400		MMBtu/year =	136		

From CARB/EPA Certified Data Pollutant	Emission Factor (g/kw-hr)	Emission Factor (g/hp-hr)	Max. Hourly (lb/hour)	Max. Daily (lb/day)	Annual Emissions (lb/yr)	Annual Emissions (TPY)
NMHC+NOx	3.7	2.76				
NOx	3.52	2.62	2.311	55.47	113.26	0.0566
POC	0.19	0.14	0.122	2.92	5.96	0.0030
CO	0.9	0.67	0.592	14.20	29.00	0.0145
PM10 = PM2.5	0.16	0.119	0.105	2.53	5.16	0.0026
SO2*		0.004	0.004	0.09	0.18	0.00009

Note: * Assume complete conversion of sulfur in fuel to SO2
15ppm ULSD

Toxic Air Contaminant	**Factor**	**Emissions**		**Trigger Levels**	
	(g/hp-hr)	**lb/hr**	**lb/yr**	**lb/hr**	**lb/yr**
Diesel PM	0.119	1.05E-01	5.16	-	0.34

Hazardous Air Pollutants from Fire Pump Diesel Engine
HAPs were reviewed for Federal Major Source of Hazardous Air Pollutants applicability. Impacts to health were analyzed using diesel particulate matter as a surrogate. Emission factors are from California Air Toxics Emission Factors (CATEF) database.

SOURCEID	MATERIAL	SCC	TYPE	DESCRITION	CAS	SUBSTANCE	MEAN	UNIT	Annual HAP Emissions	
3246	Diesel	20200102	None	O2>13%	106-99-0	1,3-Butadiene	5.41E-03	lbs/Mgal	5.30E-03	lb/year
3251	Diesel	20200102	None	O2>13%	75-07-0	Acetaldehyde	1.07E-01	lbs/Mgal	1.05E-01	lb/year
3252	Diesel	20200102	None	O2>13%	107-02-8	Acrolein	1.30E-02	lbs/Mgal	1.27E-02	lb/year
3256	Diesel	20200102	None	O2>13%	71-43-2	Benzene	1.22E-01	lbs/Mgal	1.20E-01	lb/year
3220	Diesel	20100102	None	O2>13%	50-32-8	Benzo(a)pyrene	3.35E-03	lbs/Mgal	3.28E-03	lb/year
3222	Diesel	20100102	None	O2>13%	205-99-2	Benzo(b)fluoranthene	6.70E-03	lbs/Mgal	6.57E-03	lb/year
3226	Diesel	20100102	None	O2>13%	207-08-9	Benzo(k)fluoranthene	6.70E-03	lbs/Mgal	6.57E-03	lb/year
3227	Diesel	20100102	None	O2>13%	218-01-9	Chrysene	3.58E-03	lbs/Mgal	3.51E-03	lb/year
3229	Diesel	20100102	None	O2>13%	53-70-3	Dibenz(a,h)anthracene	3.49E-03	lbs/Mgal	3.42E-03	lb/year
3235	Diesel	20100102	None	O2>13%	50-00-0	Formaldehyde	1.11E+00	lbs/Mgal	1.09E+00	lb/year
3238	Diesel	20100102	None	O2>13%	193-39-5	Indeno(1,2,3-cd)pyrene	3.46E-03	lbs/Mgal	3.39E-03	lb/year
3240	Diesel	20100102	None	O2>13%	91-20-3	Naphthalene	5.64E-02	lbs/Mgal	5.53E-02	lb/year
3286	Diesel	20200102	None	O2>13%	108-88-3	Toluene	5.50E-02	lbs/Mgal	5.39E-02	lb/year
3289	Diesel	20200102	None	O2>13%	1330-20-7	Xylene (Total)	3.59E-02	lbs/Mgal	3.52E-02	lb/year
								Total	**1.50E+00**	**lb/year**

Sulfuric Acid Mist (H2SO4) Estimate								
7000	grain/lb							
1022	Btu/scf							
1000000	Btu/MMBtu							
32.07	Molecular weight of Sulfur							
64.06	Molecular weight of Sulfur dioxide							
98.08	Molecular weight of Sulfuric Acid							
Assumptions								
33.3	% SO2 converts to H2SO4		Conversion based on Guidance from the National Park Service					
2150	MMBtu/hour/turbine		http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm					
17698638.3	MMBtu/year/turbine							
50.6	MMBtu/hour/boiler							
218794.4	MMBtu/year/boiler							
grain Sulfur/100 scf	lb S/MMBtu	lb SO2/MMBtu	lb H2SO4/MMBtu	lb SO2/turbine/hour	lb SO2/turbine/year	tons SO2/turbine/year	lb H2SO4/turbine/hour	ton H2SO4/turbine/year
1	0.0014	0.0028	0.0014	6.00	49417.29	24.7086	3.0607	
0.25	0.0003	0.0007	0.0004	1.50	12354.32	6.3000	0.7652	3.15
grain Sulfur/100 scf	lb S/MMBtu	lb SO2/MMBtu	lb H2SO4/MMBtu	lb SO2/boiler/hour	lb SO2/boiler/year	tons SO2/boiler/year	lb H2SO4/boiler/hour	lb H2SO4/boiler/year
1	0.0014	0.0028	0.0014	0.14	610.91	0.3100	0.0720	0.16
							Project Total =	6.45
Example Calculations								
lb S/MMBtu = 1 grain S/100 scf x 1 lb/7000 grain x 1 scf/1022 Btu x 1E06 Btu/MMBtu = 0.0014 lb S/MMBtu								
lb SO2/MMBtu = 0.0014 lb S/MMBtu x 64.06/32.07 = 0.0028 lb SO2/MMBtu								
lb H2SO4/MMBtu = 0.0028 lb SO2/MMBtu x 98.08/64.06 x 0.10 = 0.0004 lb H2SO4/MMBtu								
lb H2SO4/turbine/hour = 0.0004 lb H2SO4/MMBtu x 2150 MMBtu/hr = 0.9191 lb H2SO4/turbine/hour								

Grain Loading Calculation		
CTG (each)		
PM-10 Maximum Emission Rate	7.74	lb/hr
HHV Firing Rate	2150	MMBtu/hr
F-factor*	8743	dscf/MMBtu
lb =	7000	grain
Corrected O2%	15	%
Ambient Air O2 Concentration	20.9	%
grains/dscf = (7.74 lb/hr x 7000 grains/lb)/(2150 MMBtu/hr x 8743 dscf/MMBtu x 20.9/(20.9 - corrected O2%)		
grains/dscf @ 15% O2=	0.0008137	
grains/dscf @ 6% O2=	0.0020548	
Boiler		
PM-10 Maximum Emission Rate	0.3542	lb/hr
HHV Firing Rate	50.6	MMBtu/hr
F-factor *	8743	dscf/MMBtu
lb =	7000	grain
Corrected O2%	3	%
Ambient Air O2 Concentration	20.9	%
grains/dscf = (0.3542 lb/hr x 7000 grains/lb)/(50.6 MMBtu/hr x 8743 dscf/MMBtu x 20.9/(20.9 - corrected O2%		
grains/dscf @ 3% O2=	0.0048	
grains/dscf @ 6% O2=	0.0039955	
Fire Pump		
PM-10 Maximum Emission Rate	0.105	lb/hr
HHV Firing Rate	2.78	MMBtu/hr
F-factor*	9083	dscf/MMBtu
lb =	7000	grain
Corrected O2%	0	%
Ambient Air O2 Concentration	20.9	%
grains/dscf = (0.09 lb/hr x 7000 grains/lb)/(2.66 MMBtu/hr x 9048 dscf/MMBtu x 20.9/(20.9 - corrected O2%))		
grains/dscf =	0.0291687	
For compliance with Regulation 8-2-301 (15 lb VOC/day and 300 ppm C limit):		
POC (lb/day) =	2.92	
Actual exhaust flowrate (ft3/min)=	2214.00	
POC (lb/hr) = 0.12		
POC (ppm) = (0.122 lb/hr x 10^6 x 386.8 ft3/lbmol)/(16 lb/lbmol x 2214 ft3/min*60 min/hr)		
POC (ppm) = 17632.05		
*Source: http://www.epa.gov/ttn/emc/promgate/m-19.pdf Equation 19-13		

Evaporative Fluid Cooler [Exempt from Air District Permits per Regulation 2-1-128.4]

Max Operating Rate	5880	gal/min
	352800	gal/hour
Max drift rate	0.003%	
Max drift rate (lb of water/hour)	88.2	lb water/hr
Max Total Dissolved Solids (TDS)	1500	mg/liter (ppm)
Hours of Operation	24	hours/day
	1500	hours/year

Pollutant	Hourly	Daily	Annual	Annual
	lb/hour	lb/day	lb/yr	tons/yr
PM10/2.5	0.132	3.174	198.371	0.099

Example Calculation

(352,800 gal/hr)(8.33 lb/gal)(0.003%)(1500ppm)/(10^6) = 0.132 lb PM/hr

Toxic Air Contaminant	Initial Concentration in Water	Average Cycles of	Concentration in Drift Water	Emissions		Trigger Levels	
	ppm*	Concentration*	ppm	lb/hr	lb/yr	lb/hr	lb/yr
Arsenic	0.069	3	0.207	1.83E-05	2.74E-02	4.40E-04	7.20E-03
Copper	0.177	3	0.531	4.68E-05	7.03E-02	2.20E-01	None
Lead	0.0497	3	0.1491	1.32E-05	1.97E-02	None	3.2

*provided by Applicant. Amended AFC Table 5.1A-7

For compliance with Regulation 6-1-311:

Emission limit (lb/hr) = 4.10 Process weight^0.67

Process weight = 352800 gal/hour x 8.33 lb/gal = 2938824 lb/hr = 1469.4 ton/hr

Emission limit = (4.10)(1469.4^0.67) = 542.96 lb PM/hour

Oil-Water Separator [Exempt from Air District Permits per Regulation 2-1-103.1 and 8-8-113]

Max Operating Rate	120	gal/hr
	0.12	1000 gal/hr
Hours of Operation	24	hours/day
	365	day/year

Pollutant	Emission Factor	Hourly	Daily	Annual	Annual
	lb/1000 gallons	**lb/hour**	**lb/day**	**lb/yr**	**tons/yr**
VOC*	0.2	0.024	0.576	210.240	0.105

*Emission Factor from AP-42, Section 5.1 Petroleum Refining,
Table 5.1-2 Fugitive Emission Factors For Petroleum Refineries - Oil/Water Separators controlled emissions, 1/95

Memorandum
September 7, 2005

To: Engineering Division Staff

From: Brian Bateman
Director of Engineering

Subject: Emission Factors for Toxic Air Contaminants from Miscellaneous Natural Gas Combustion Sources

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This memorandum serves to provide guidelines on the emission factors to use to calculate toxic air contaminant (TAC) emissions from miscellaneous natural gas combustion sources. When site specific or source category specific emission factors are not available, the following emission factors shall be used to calculate TAC emissions from miscellaneous natural gas combustion sources:

TAC Emission Factors for Miscellaneous Natural Gas Combustion		
TAC	Emission Factor, lbs/Mscf	Emission Factor, lbs/therms *
Benzene	2.1 E-6	2.06 E-7
Formaldehyde	7.5 E-5	7.35 E-6
Toluene	3.4 E-6	3.33E-7

* based on 1020 Btu/scf

These emission factors are taken from AP42 Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion, and are those for which a reasonable number of sources had been tested and the tests were performed using sound methodology. AP42 emission factors for PAHs are not used because they are based on single tests in which the speciated PAH emissions were found to be below detection levels. AP42 emission factors for metal emissions are not used because they are based on a small number of tests and have poor EPA data quality ratings. CATEF factors are not used because there was inadequate data, the data quality was poor, or the quality of AP42 data was better. Based on the data from their websites, neither Ventura nor San Diego APCD use metal emission factors and except for naphthalene, neither uses any other speciated or benzo(a)pyrene equivalent PAH emission factor.

BFB:SBL:jhl

Appendix B

Health Risk Assessment Results

INTEROFFICE MEMORANDUM
AUGUST 12, 2010

TO: **Kathleen Truesdell** **Via:** **Scott B. Lutz**
Daphne Y. Chong

FROM: **Glen Long**

SUBJECT: **Results of Health Risk Screening Analysis for Contra Costa Generating Station LLC [also known as Oakley Generating Station] (Oakley, CA), Combined Cycle Power Plant, Plant #19771, Application #20798**

Per your request, we have completed a health risk screening analysis for the above referenced permit application. The analysis estimates the incremental health risk resulting from toxic air contaminant (TAC) emissions from the operation of two gas powered turbines, an auxiliary boiler, a three-cell evaporative condenser, and a fire pump. Results from the health risk screening analysis indicate that the project maximum cancer risk is estimated at 1.56 in a million, a chronic non-cancer hazard index of 0.0832, and an acute hazard index of 0.2665. The risk from each source individually is below 1.0 in a million maximum individual cancer risk and the chronic hazard index is less than 0.20. In accordance with the District's Regulation 2, Rule 5, this source is in compliance with all project risk requirements.

EMISSIONS: TAC emission were obtained from your August 10, 2010 emissions spreadsheet for the facility. Table I summarizes these emissions.

MODELING: The AERMOD air dispersion computer model was used to estimate maximum one-hour and annual average ambient air concentrations. AERMET was used to create two sets of five years of data with the Contra Costa Power meteorological data (2001-2002 and 2004-2006; 2003 did not meet the EPA required data recovery rates). The first set, Contra Costa Power (CCP), was processed using the land use characteristics around the meteorological tower. The second set was also created with the Contra Costa Power meteorological data, but the site characteristics around the proposed project site were used. All maximum impacts occurred using the CCGS data. Stack and building parameters for the analysis were based on information provided by the applicant.

HEALTH RISK: AERMOD results were imported into HARP using the HARP on-ramp module and the latest version of HARP (version 1.4a) was used to predict all health impacts. Estimates of residential risk assume potential exposure to annual average TAC concentrations occur 24 hours per day, 350 days per year, for a 70-year lifetime. The HARP option "Derived (Adjusted) Method" was used for calculating residential cancer risks. Risk estimates for offsite workers assume potential exposure occurs 8 hours per day, 245 day per year, for 40 years. The HARP default exposure assumptions were used for calculating worker cancer risks. Cancer risk adjustment factors (CRAFs) were used to calculate all cancer risk estimates. The CRAFs are age-specific weighting factors used in calculating cancer risks from exposures of infants, children and adolescents, to reflect their anticipated special sensitivity to carcinogens. There are no schools located within 1000 feet of the facility. Shown in Figures 1-4 are the cancer risk and the chronic hazard index for both residents and workers. Shown in Figure 5 is the acute hazard index. The estimated health risks for this permit application at the Point of Maximum Impact (PMI) are presented in Table II. Shown in Table III is the maximum cancer risk from each source. Because the cancer risk for each source is less than 1.0 in one million and the chronic hazard index for each source is less than 0.20, and because the total project risk is less than 10 in one million and the project chronic hazard index and acute hazard index are less than 1.0, the project complies with all of the toxic risk requirements of District Regulation 2, Rule 5.

Table I: Maximum Oakley Generating Station TAC emissions.

	Turbines		Boiler		Evaporative Cooler		Firepump	
Toxic Air Contaminant	Max 1- hour Emissions per turbine including tuning (lb/hr)	Max Annual lb/yr	Max 1- hour Emissions lb/hr	Max Annual lb/yr	Max 1- hour Emissions per cell (lb/hour)	Max Annual per cell (lb/yr)	Max 1- hour Emissions lb/hour	Max Annual lb/yr
1,3-Butadiene	2.672080E-04	2.199342E+00						
Acetaldehyde	2.693120E+00	2.476060E+03						
Ammonia	1.466053E+01	1.206682E+05	0.000000E+00	0.000000E+00				
Benzene	5.386240E-02	2.314390E+02	1.039500E-04	4.491900E-01				
Benzo(a)anthracene	4.755040E-05	3.913789E-01						
Benzo(a)pyrene	2.924560E-05	2.407153E-01						
Benzo(b)fluoranthene	2.377520E-05	1.956894E-01						
Benzo(k)fluoranthene	2.314400E-05	1.904942E-01						
Chrysene	5.302080E-05	4.364048E-01						
Dibenz(a,h)anthracene	4.944400E-05	4.069648E-01						
Ethylbenzene	6.859040E-02	3.113176E+02						
Formaldehyde	9.741520E+00	8.318029E+03	3.712500E-03	1.604250E+01				
Hexane	5.449360E-01	4.485271E+03						
Indeno(1,2,3-cd)pyrene	4.944400E-05	4.069648E-01						
Naphthalene	3.492640E-03	2.874730E+01						
Propylene	1.622184E+00	1.335191E+04						
Propylene Oxide	1.005712E-01	8.277837E+02						
Toluene	2.066128E-01	1.232017E+03	1.648350E-07	7.272600E-01				
Xylene (Total)	5.491440E-02	4.519907E+02						
Sulfuric Acid Mist (H2SO4)	3.061071E+00	6.397629E+03	7.203230E-02	1.557338E-01				
Arsenic					6.085800E-06	9.128700E-03		
Copper					1.561140E-05	2.341710E-02		
Lead					4.383540E-06	6.575310E-03		
Diesel PM							1.052157E-01	5.155457E+00

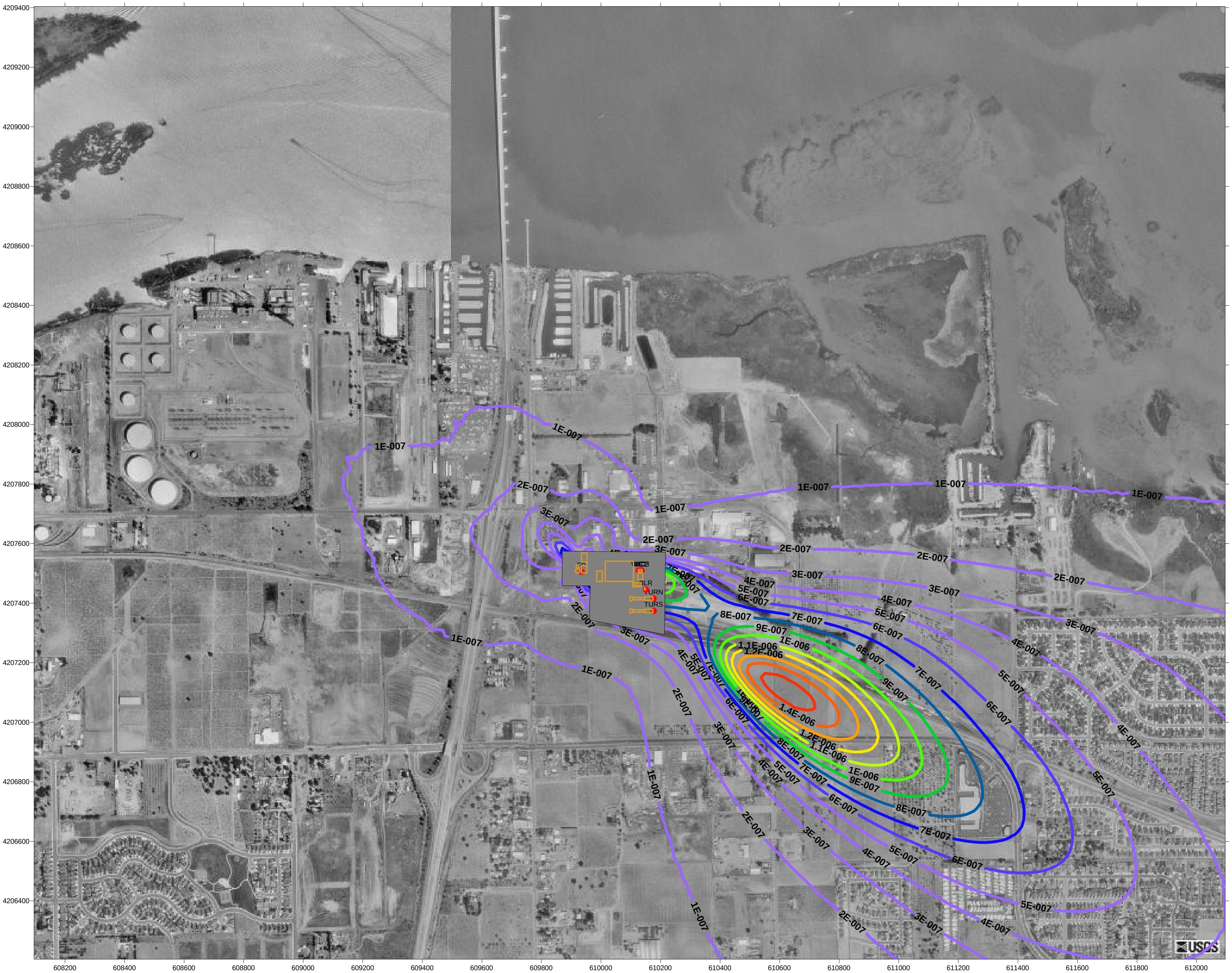
Table II. Maximum project health effects.

Receptor	Cancer Risk	Chronic Non-cancer Hazard Index	Acute Hazard Index
Resident	1.56 chances in a million	0.0832	0.2665
Worker	0.14 chances in a million	0.0790	

Table III. Maximum cancer risk from each source.

Source	Maximum Residential/Worker Cancer Risk from source
North Turbine	0.70 in a million
South Turbine	0.65 in a million
Auxiliary Boiler	0.03 in a million
Evaporative Cooler	0.39 in a million
Fire Pump	0.73 in a million

Figure 1: Oakley Generating Station Residential Cancer Risk

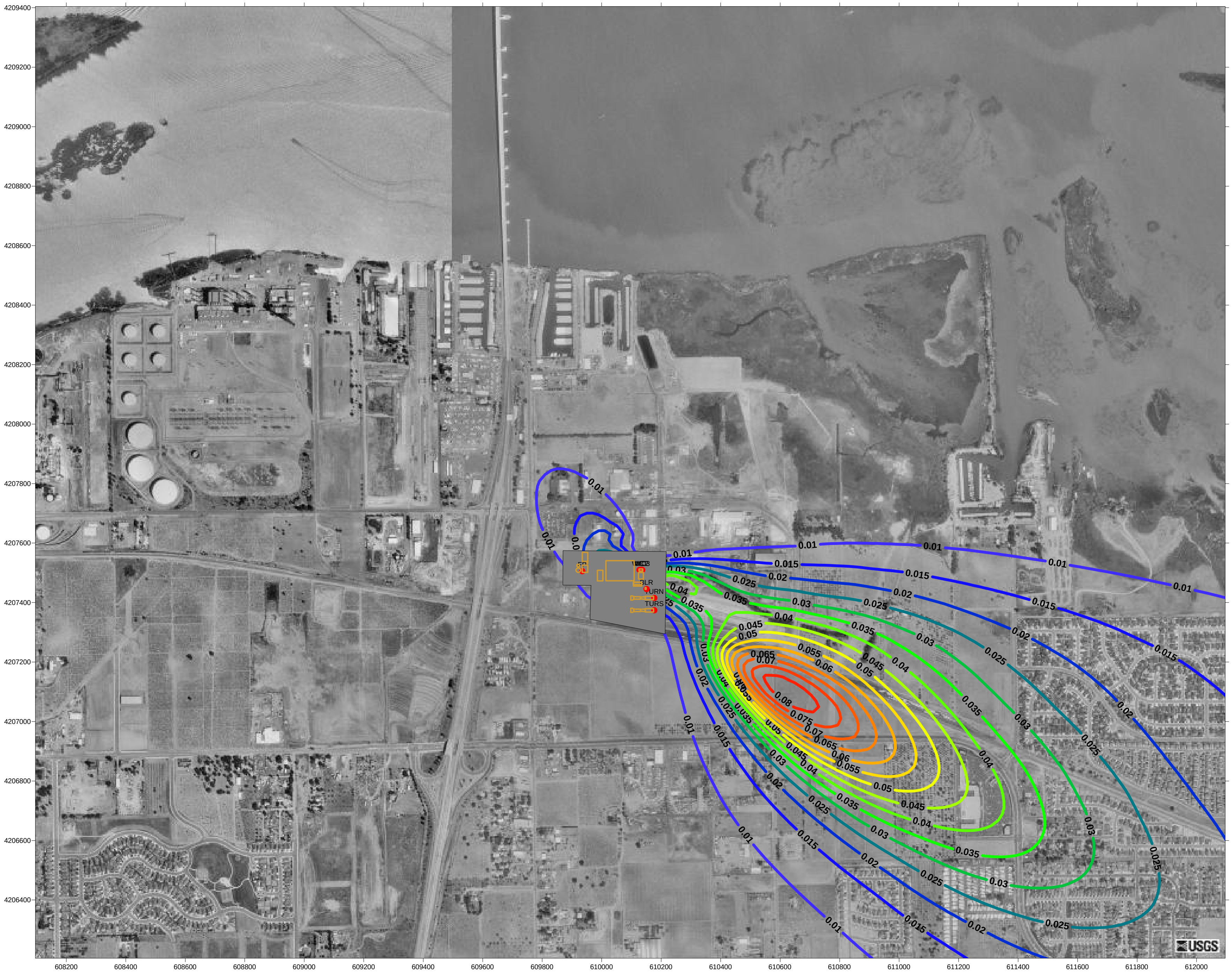


Met data:CCGS
August 12, 2010

Figure 2: Oakley Generating Station Worker Cancer Risk

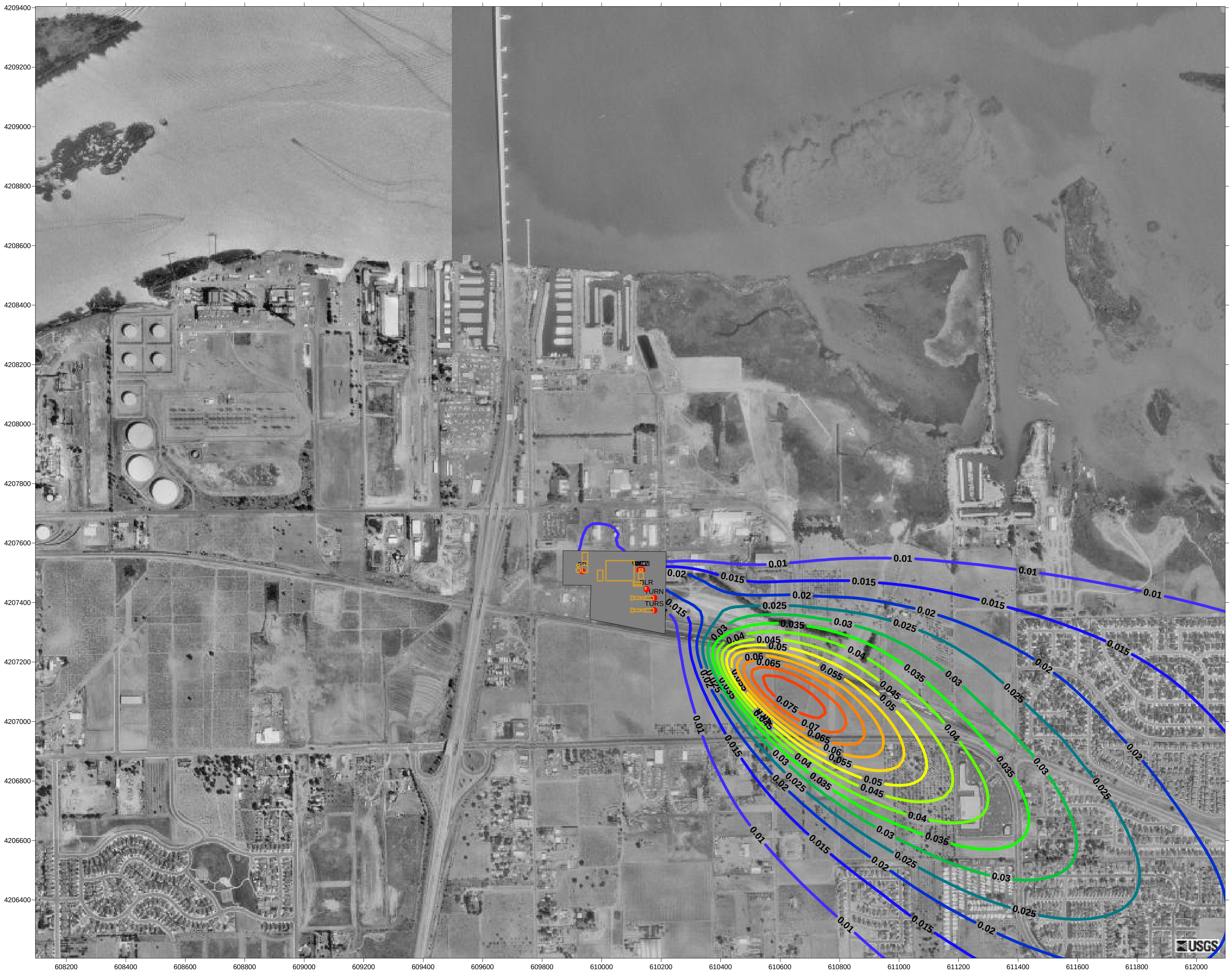
Met data:CCGS
August 12, 2010

Figure 3: Oakley Generating Station Residential Chronic HI



Met data:CCGS
August 12, 2010

Figure 4: Oakley Generating Station Worker Chronic HI



Met data:CCGS
August 12, 2010

Figure 5: Oakley Generating Station Acute HI

Met data:CCGS
August 12, 2010