Revised Air Quality Staff Assessment

MOUNTAINVIEW POWER PLANT PROJECT

Application For Certification 00-AFC-2
City of Redlands, San Bernardino County

CALIFORNIA
ENERGY
COMMISSION

STAFF REPORT

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CALIFORNIA ENERGY COMMISSION

SITING OFFICE

James W. Reede, Jr.
Energy Commission Project Manger

Roger E. Johnson,
Manager

ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION

Robert L. Therkelsen
Deputy Director

AIR QUALITY

Joseph M. Loyer

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the planned construction and operation of the Mountainview Power Plant (MVPP) as proposed by the Mountainview Power Company, LLC (MVPC). Criteria air pollutants are defined as those for which a state or federal ambient air quality standard has been established to protect public health. They include nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), ozone (O3), volatile organic compounds (VOC) and particulate matter less than 10 microns in diameter (PM10).

In carrying out this analysis, the California Energy Commission staff evaluated the following major points:

- whether the MVPP is likely to conform with applicable Federal, State and South Coast Air Quality Management District air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1742.5 (b);
- whether the MVPP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- whether the mitigation proposed for the MVPP is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1744 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Under the Federal Clean Air Act (40 CFR 52.21), there are two major components of air pollution law, New Source Review (NSR) and Prevention of Significant Deterioration (PSD). NSR is a regulatory process for evaluation of those pollutants that violate federal ambient air quality standards. Conversely, PSD is a regulatory process for evaluation of those pollutants that do not violate federal ambient air quality standards. The NSR analysis has been delegated by the Environmental Protection Agency (EPA) to the South Coast Air Quality Management District (District). The EPA determines the conformance with the PSD regulations. The PSD requirements apply only to those projects (known as major sources) that exceed 100 tons per year for any pollutant.

STATE

The California State Health and Safety Code, section 41700, requires that no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property.

LOCAL - SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

The proposed project is subject to the following South Coast Air Quality Management District rules and regulations:

REGULATION II — PERMITS

This regulation sets forth the regulatory framework of the application for and issuance of construction and operation permits for new, altered and existing equipment.

RULE 202 — TEMPORARY PERMIT TO OPERATE

This rule states that any new equipment that has been issued a Permit to Construct (PTC) shall be allowed to use that PTC as a temporary Permit to Operate (PTO) upon notification to the Air Pollution Control Officer (APCO).

RULE 203 — PERMIT TO OPERATE

This rule prohibits the use of any equipment that may emit air contaminants or control the emission of air contaminants, without first obtaining a PTO except as provided in Rule 202.

RULE 217 — PROVISIONS FOR SAMPLING AND TESTING

The Executive Officer (EO) may require the applicant to provide and maintain facilities necessary for sampling and testing. The EO will inform the applicant of the need for testing ports, platforms and utilities.

RULE 218 — CONTINUOS EMISSION MONITORING

This rule describes the installation, QA/QC and reporting requirements for all sampling interfaces, analyzers and data acquisition systems used to continuously determine the concentration or mass emission of an emission source. However, this rule does not apply to the CEMS required for NOx monitoring under RECLAIM (Regulation XX).

REGULATION IV — PROHIBITIONS

This regulation sets forth the restrictions for visible emissions, odor nuisance, fugitive dust, various air emissions, fuel contaminants, start-up/shutdown exemptions and breakdown events. Please note that San Bernardino County

Rule 53 and 53A have not been superseded by District rules and may apply to this project.

Rule 401 — Visible Emissions

Generally this rule restricts visible emissions from a single source for more than three minutes in any one hour from being as dark or darker than that designated on the No. 1 Ringelman Chart (US Bureau of Mines).

Rule 402 — Nuisance

This rule restricts the discharge of any contaminant in quantities which cause or have a natural ability to cause injury, damage, nuisance or annoyance to businesses, property or the public.

Rule 403 — Fugitive Dust

This rule requires that the applicant prevent, reduce or mitigate fugitive dust emissions from the project site. Rule 403 restricts visible fugitive dust to the project property line, restricts the net PM10 emissions (between up and down wind measurements) to less than 50 ug/m^3 and restricts the tracking out of bulk materials onto public roads. Additionally, the applicant must utilize one or more of the best available control measures (identified in the tables within the rule). Mitigation measures may include, adding freeboard to haul vehicles, covering loose material on haul vehicles, watering, using chemical stabilizers and/or ceasing all activities. Finally, a contingency plan maybe required if so determined by the US EPA.

Rule 407 — Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2,000 ppm and SO2 emissions to 500 ppm, averaged over 15 minutes. However, internal combustion engines are exempt from the SO2 limit, as are equipment that comply with rule 431.1. The applicant will comply with rule 431.1 and thus the sulfur limit of rule 407 will not apply.

Rule 408 — Circumvention

This rule allows the concealment of emissions released to the atmosphere in cases where the only violation involved is of Section 48700 of the Health and Safety Code or District Rule 402.

Rule 409 — Combustion Contaminants

This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter of gas, calculated to 12% CO_2, averaged over 15 minutes. This rule does not apply to IC engines or jet engine test stands.

Rule 431.1 — Sulfur Content of Gaseous Fuels

This rule restricts the sale or use of gaseous fuels that exceed a sulfur content limit. The sulfur content limit for natural gas is 16 ppmv calculated as H_2S. This rule also establishes monitoring and reporting requirements, as well as test methods to be used.

RULE 431.2 — SULFUR CONTENT OF LIQUID FUELS

This rule establishes a sulfur content limit for diesel fuel of 0.05% by weight, as well as, record keeping requirements and test methods.

RULE 475 — ELECTRIC POWER GENERATING EQUIPMENT

This rule limits combustion contaminants (PM10) from electric power generating equipment to 11 pounds per hour and 23 milligrams per cubic meter @ 3% O_2 (averaging time subject to Executive Officer decision).

REGULATION VII — EMERGENCIES

RULE 701 — AIR POLLUTION EMERGENCY CONTINGENCY ACTIONS

This rule requires that facilities employing 100 or more people or emitting 100 or more tons of pollutants (NOx, SOx or VOC) per year, upon declaration or prediction of a Stage 2 or 3 episode, reduce NOx, SOx and VOC emissions by at least 20% of normal workday operations. This rule also requires that upon declaration of a state of emergency by the Governor, that the facility comply with the Governor s requirements. A power plant facility may be exempt from Rule 701 if they are determined to be an essential service responding to a public emergency or utility outage.

REGULATION IX — STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Regulation IX incorporates provisions of Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR) and is applicable to all new, modified or reconstructed sources of air pollution. Sections of this regulation apply to electric utility steam generators (Subpart Da) and stationary gas turbines (Subpart GG). These subparts establish limits of particulate mater, SO2 and NO2 emissions from the facility as well as monitoring and test method requirements.

REGULATION XI — SOURCE SPECIFIC STANDARDS

RULE 1110.1 — EMISSIONS FROM STATIONARY INTERNAL COMBUSTION ENGINES

This rule generally applies to engines larger that 50 brake horsepower (bhp) and places restriction on rich-burn or lean-burn engines. These restrictions are in the form of NOx and CO emission limits and the required submittal of a control plan to demonstrate compliance. Emergency standby engines, operating less than 200 hours per year are exempt from Rule 1110.1.

RULE 1110.2 — EMISSIONS FROM GAS AND LIQUID FUELED ENGINES

This rule establishes NOx, VOC and CO emissions limits for stationary and portable engines over 50 bhp in rated capacity. Emergency standby engines, operating less than 200 hours per year are exempt from Rule 1110.2.

REGULATION XIII — NEW SOURCE REVIEW

This regulation sets forth the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. This regulation limits the emissions of non-attainment contaminants and their precursors as well as ozone depleting compounds (ODC) and ammonia by requiring the use of Best Available Control Technologies (BACT). However, this regulation does not apply to NOx or SOx emissions, which are regulated by Regulation XX (RECLAIM).

REGULATION XVII —PREVENTION OF SIGNIFICANT DETERIORATION

This regulation sets forth the pre-construction requirement for stationary sources to ensure that the air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth. This regulation establishes maximum allowable increases over ambient baseline concentrations for each pollutant. It is likely that the MVPP will trigger PSD for NOx only.

REGULATION XX — REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

The Regional Clean Air Incentives Market (RECLAIM) is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications, reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reductions. The RECLAIM program establishes an initial allocation (beginning in 1994) and an ending allocation (to be attained by the year 2003) for each facility within the program (Rule 2002). Each facility then reduces their allocation annually on a straight line from the initial to the ending. The RECLAIM program supercedes other district rules, where there are conflicts. As a result, the RECLAIM program has its own rules for permitting, reporting, monitoring (including CEM), record keeping, variances, breakdowns and the New Source Review program, which incorporates BACT requirements (Rules 2004, 2005, 2006 and 2012). RECLAIM also has its own banking rule, RECLAIM Trading Credits (RTCs), which is established in Rule 2007. The MVPP is exempt from the SOx RECLAIM program (Rule 2011) because it uses natural gas exclusively (per Rule 2001). However, it will be a NOx RECLAIM project and therefore subject to the rules of RECLAIM for NOx emissions.

REGULATION XXX — TITLE V PERMITS

The Title V federal program is the air pollution control permit system require by the federal Clean Air Act as amended in 1990. Regulation XXX defines the permit application and issuance as well as compliance requirements associated with the program. Any new or modified major source which qualifies as a Title V facility must obtain a Title V permit prior to construction, operation or modification of that source. Regulation XXX also integrates the Title V permit with the RECLAIM program such that a project cannot proceed without the other.

REGULATION XXXI — ACID RAIN PERMITS

Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOX, NOx and CO2 emissions from the facility.

LOCAL - SAN BERNARDINO COUNTY

At this time it is unclear what agency will be enforcing these rules, the District or the County.

RULE 53 — SPECIFIC CONTAMINANTS

This rule restricts the emission of sulfur to 0.1% by volume and combustion contaminants to 0.3 grain per cubic foot at 12% CO_2. This rule also restricts the emissions of fluorine to less than that which would cause injury to the property of others.

RULE 53A — SPECIFIC CONTAMINANTS

This rule restricts the emission of SO2 to 500 ppm at 12% CO2, combustion contaminants to 0.1 grains per cubic foot at 12% CO2 and several other non-criteria pollutants.

ENVIRONMENTAL SETTING

METEOROLOGICAL CONDITIONS

The general climate of California is typically dominated by the eastern Pacific high pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rain storms originating in the Gulf of Alaska and striking Northern California.

The large scale wind flow patterns in the South Coast basin are a diurnal cycle driven by the differences in temperature between the land and the ocean as well as the mountainous terrain surrounding the basin. The Tehachapi and Temblor Mountains separate the South Coast and San Joaquin Valley air basins. The San Bernardino, San Gabriel and Santa Rosa mountains generally make up the eastern mountain range of the South Coast air basin. The Santa Monica and Santa Ana Mountains make up the northern and southern (respectively) coastal mountain ranges of the South Coast air basin.

The project site is located in the City of Redlands, in San Bernardino County. The project site is at an elevation of approximately 1,100 feet above sea level. To the west of the project site, the terrain is generally flat, to east the terrain slopes upward, reaching 1,600 feet approximately 6 miles from the project. The Box Spring Mountains are approximately 2.5 miles south of the project site, raising to approximately 2,000 feet within 8 miles of the project site. The local mountain ranges nearest the project site are the San Gabriel Mountains (north-west of the project site), the San Bernardino Mountains (north-east), the Jurupa Mountains (south-west) and the Box Spring Mountains (south). The San Bernardino National Forest (a class 1 area) is approximately 5_ miles to the northeast of the project site.

Wind patterns in the San Bernardino area are typically from the west and west-northwest direction. The strongest winds range between 7 and 10 knots and almost 16% of the winds are calm. Temperatures range from the low 40^{o}F to the mid 90^{o}F. The inversion layer within the San Bernardino area of the South Coast basin is typically low, 70-90 meters in fall and winter, 255 meters in the spring and 150 meters in the summer. Such low inversion layers can contribute significantly to severe air quality impacts. Such impacts are typical for this area.

EXISTING AIR QUALITY

The Federal Clean Air Act and the California Air Resources Board (CARB) both required the establishment of allowable maximum ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically lower (more protective) than the federal AAQS, which are established by the EPA. The state and federal air quality standards are listed in AIR QUALITY Table 1. As indicated in AIR QUALITY Table 1, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to an annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 and $\mu g/m^3$).

In general, an area is designated as attainment for a specific pollutant if the concentrations of that air contaminant do not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of a district is usually evaluated to determine the district s attainment status.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O3)	1 Hour	0.12 ppm (235 $\mu g/m^3$)	0.09 ppm (180 $\mu g/m^3$)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO2)	Annual Average	0.053 ppm (100 $\mu g/m^3$)	---
	1 Hour	---	0.25 ppm (470 $\mu g/m^3$)
Sulfur Dioxide (SO2)	Annual Average	80 $\mu g/m^3$ (0.03 ppm)	---
	24 Hour	365 $\mu g/m^3$ (0.14 ppm)	0.04 ppm (105 $\mu g/m^3$)
	3 Hour	1300 $\mu g/m^3$ (0.5 ppm)	---
	1 Hour	---	0.25 ppm (655 $\mu g/m^3$)
Respirable Particulate Matter (PM10)	Annual Geometric Mean	---	30 $\mu g/m^3$
	24 Hour	150 $\mu g/m^3$	50 $\mu g/m^3$
	Annual Arithmetic Mean	50 $\mu g/m^3$	---
Sulfates (SO_4)	24 Hour	---	25 $\mu g/m^3$
Lead	30 Day Average	---	1.5 $\mu g/m^3$
	Calendar Quarter	1.5 $\mu g/m^3$	---
Hydrogen Sulfide (H_2S)	1 Hour	---	0.03 ppm (42$\mu g/m^3$)
Vinyl Chloride (chloroethene)	24 Hour	---	0.010 ppm (26 $\mu g/m^3$)
Visibility Reducing Particulates	1 Observation	---	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

The MVPP is located in San Bernardino County and is under the jurisdiction of the South Coast Air Quality Management District (District). AIR QUALITY Table 2 shows the attainment or non-attainment status of the District for each criteria pollutant for both the federal and state ambient air quality standards. The federal classifications go from moderate to extreme.

AIR QUALITY Table 2
Attainment ~ Non-Attainment Classification
South Coast Air Quality Management District

Pollutants	Federal Classification	State Classification
Ozone	Extreme Non-Attainment	Non-Attainment
PM10	Non-Attainment[1]	Non-Attainment
CO	Serious Non-Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
1 The San Bernardino County area has been designated a Non-Attainment area for the federal PM10 ambient air quality standard, not the entire South Coast air basin.		

OZONE

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted air pollutants. Nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOCs]) interact in the presence of sunlight to form ozone. The District is designated extreme non-attainment for ozone, meaning that the South Coast air basin ambient ozone concentration is 0.280 ppm or above and it will take longer than 17 years (from 1990) to reach attainment. Attaining the federal ozone ambient air quality standard is typically planned for by controlling the ozone precursors NO_2 and VOC. The 1997 Ozone State Implementation Plan for the South Coast Air Basin (SCAQMD 1999) relies on the California Air Resource Board (CARB) to control mobile sources, the US Environmental Protection Agency (US EPA) to control emission sources under federal jurisdiction and SCAQMD to control local industrial sources (essentially through RECLAIM). Through these control measures, California and SCAQMD are required to reach attainment of the federal ozone ambient air quality standard by 2010.

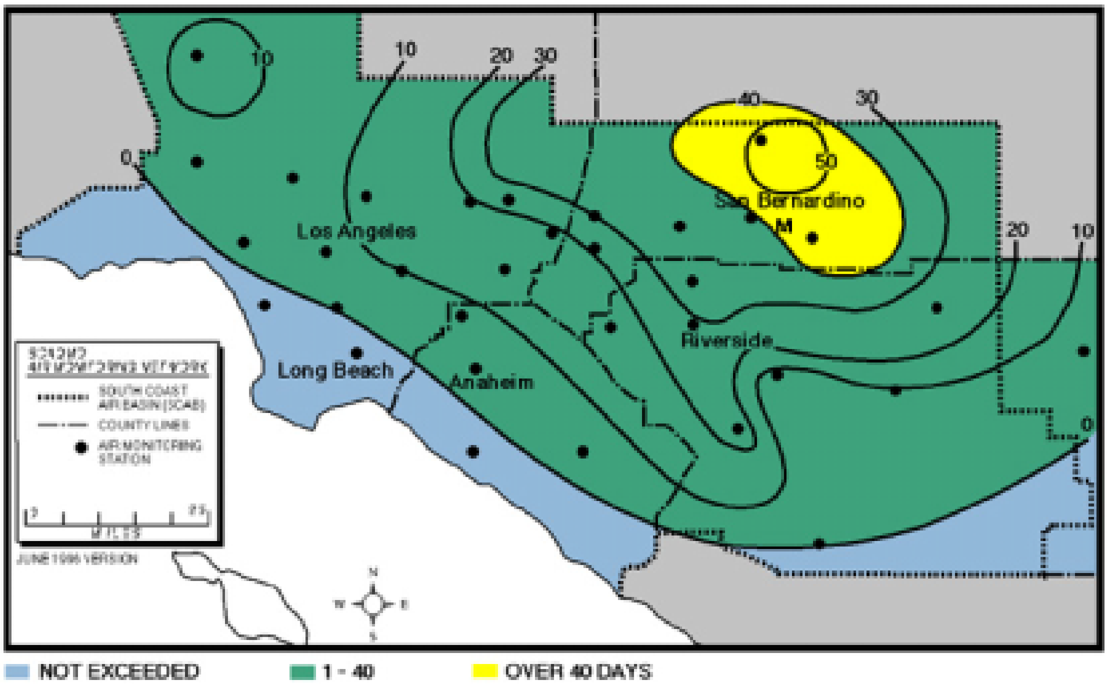
Exceedances of the national (and state) ozone ambient air quality standards occur for both the 1-hour are centered in the San Bernardino area (see AIR QUALITY Figure 1). In 1998, the South Coast air basin experienced more exceedances of the federal ozone standards than anywhere else in the United States. As AIR QUALITY Figure 1 shows, the highest number of exceedances of the federal ozone standards in 1998 occurred in the Central San Bernardino Mountains. This is also the location of the highest recorded measurement of ozone (0.24 ppm). The approximate location of the project site is indicated in AIR QUALITY Figure 1 with an **M**.

The 1999 statistics show a very similar trend, the Central San Bernardino Mountains lead the South Coast air basin in number of violations and highest ozone measurements. In 1999, there were 30 violations of the national 1-hour ozone standard and 93 violations of the state 1-hour ozone standard with the highest 1-hour measurement of ozone being 0.17 ppm.

AIR QUALITY Figure 1

OZONE – 1998

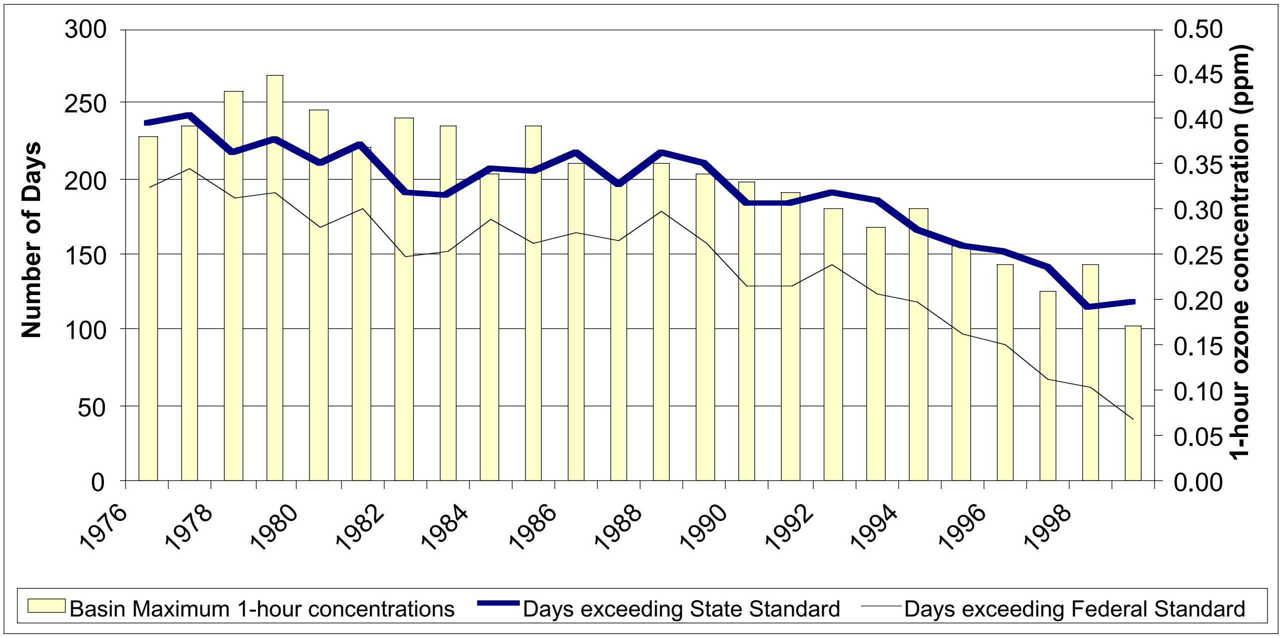
Number of Days Exceeding the Federal Standard
(1-hour average > 0.12 ppm)



Source: 1998 Air Quality Standards Compliance Report, South Coast Air Quality Management District

Though there are a significant number of exceedences of the ozone ambient air quality standards, it is important to consider the improvements that have occurred in recent years. The SCAQMD leads the nation in air quality management methods and regulatory programs. These programs have significantly improved the air quality in spite of the growing population and industrial and commercial enterprises. AIR QUALITY Figure 2 shows the improvements in exceedences of the federal and state 1-hour ozone standards and maximum annual ozone concentrations over the past 20 years in the South Coast air basin.

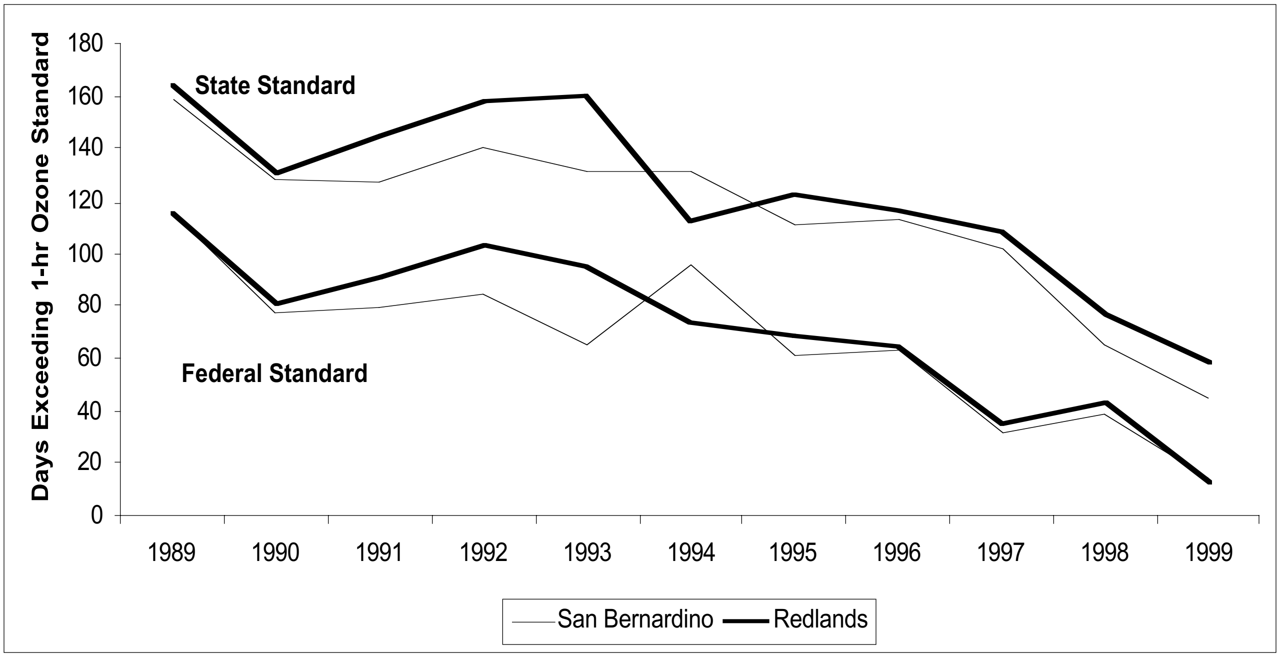
AIR QUALITY Figure 2
Historic Ozone Air Quality Trends of the South Coast Air Basin
1976 to 1999



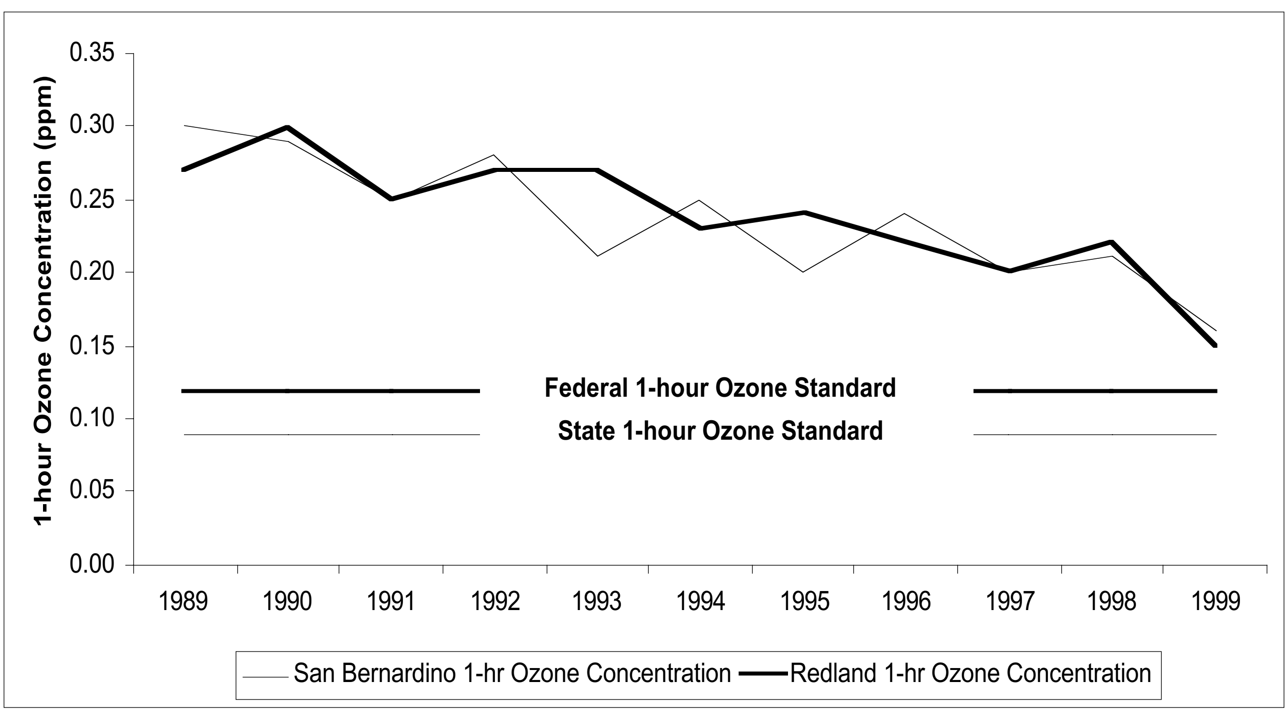
Source: South Coast Air Quality Management District

The project site has two air quality monitoring stations nearby. One in the City of San Bernardino on 4th street (4 miles to the west-northwest) and the other in the City of Redlands on Dearborn street (5.5 miles to the east-southeast). AIR QUALITY Figure 3 shows the general trends of exceedences of the 1-hour ozone standards near the project site using the monitoring data from these two stations. As can be seen, there is a significant downward trend in the number of days exceeding the federal and state 1-hour ozone standards from 1989 to 1999. AIR QUALITY Figure 4 shows the maximum annual 1-hour ozone concentrations measured at both monitoring stations from 1989 to 1999. AIR QUALITY Figure 4 demonstrates a downward trend in ozone formation near the project site. Given the overall trends in ozone formation in the South Coast air basin and near the power plant site, staff proposes to use the lowest 1- hour annual maximum ozone measurements to describe the background air quality conditions. The lowest annual maximum 1-hour ozone concentration was measured at the San Bernardino monitoring station in 1999 at 0.15 ppm.

AIR QUALITY Figure 3
Ozone Trend — Days Exceeding the State and Federal 1-hour Standard
1989 to 1999

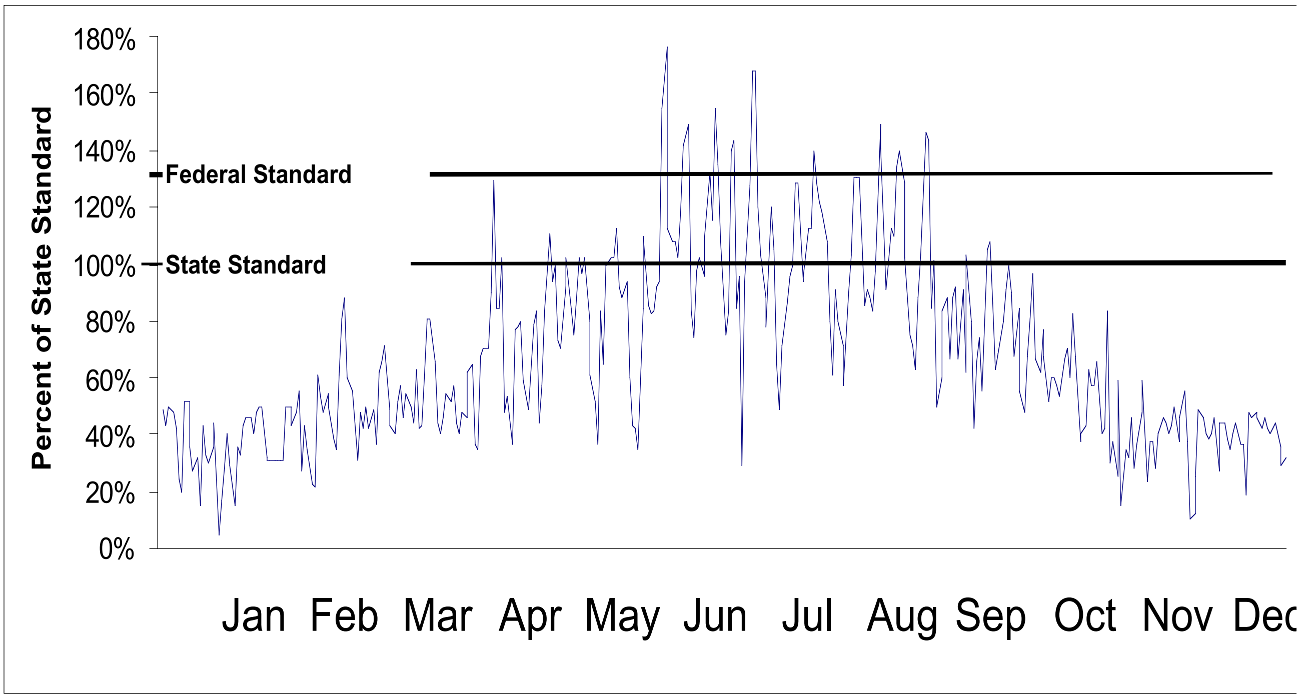


AIR QUALITY Figure 4
Maximum Measured Annual 1-hour Ozone Concentrations
1989 to 1999



AIR QUALITY Figure 5 shows the 1-hour daily maximum ozone measurement taken at the San Bernardino 4th street monitoring station. This data indicates that near the project site, the ozone violations occur primarily from April through September.

AIR QUALITY Figure 5
1999 Maximum Daily Ozone Measurements
San Bernardino, 4th Street Monitoring Station



OZONE TRANSPORT

The transportation of ozone and ozone precursors (NOx and VOC) outside of their air district or air basin of origin may cause or contribute to exceedances of the ozone air quality standards in a down wind areas. In their most recent report on the contribution of upwind air basins to ozone violations in downwind air basins (CARB 1996), the California Air Resources Board identifies several transport couplings for the South Coast air basin (see AIR QUALITY Table 3). These couplings come in three qualitative varieties, Overwhelming, Significant and Inconsequential. Overwhelming couplings indicate that emissions from the upwind area caused a violation of the state 1-hour ozone standard (0.09 ppm) on at least one day independently of any emission sources within the downwind area. Significant couplings indicate that emissions from the upwind area contribute, but not overwhelmingly, to a violation of the state 1-hour ozone standard. Inconsequential couplings indicate that emissions from the upwind area were not transported or did not contribute significantly to a violation of the state 1-hour ozone standard.

AIR QUALITY Table 3
Transport Couples for the South Coast Air Basin

Transport Couple	Characterization
South Coast to Mojave Desert	O, S
South Coast to San Diego	O,S, I
South Coast to Salton Sea	O, S
South Coast to South Central Coast	S, I
South Central Coast to South Coast	S, I
Southeast Desert (now Mojave and Salton Sea) to South Coast	I
O — Overwhelming S — Significant I — Inconsequential	

In the case of the South Coast air basin, there are several downwind areas. In May 1996, CARB split the Southeast Desert air basin into the Mojave Desert and Salton Sea air basins. CARB determined that the South Coast air basin contributions to violations of the state 1-hour ozone standard in the Mojave Desert air basin where overwhelming on some days and significant on others, with inconsequential contributions occurring less frequently than once per year. CARB also determined that the South Coast air basin contributions to violations of the state 1-hour ozone standard in the Salton Sea air basin were overwhelming on some days and significant on others.

In the November 1996 Triennial Review, CARB re-enforced the 1993 findings that the South Coast air basin contributed to violations of the 1-hour state ozone standard in the San Diego air basin overwhelmingly on some days, significantly on some other days and inconsequentially on other days. However, the number of days where contributions were classified as overwhelming dropped from 20 in 1993 to 5 in 1995. The number of days that were classified as significant increased from 31 to 48 and the number of days that were classified as inconsequential increased from 39 to 43. Since there were significant improvements in ozone measurements within the South Coast air basin during this time frame (see AIR QUALITY Figure 2), it is reasonable to speculate that the improvement in ozone violations within the South Coast air basin and the transport connections outside the basin are related.

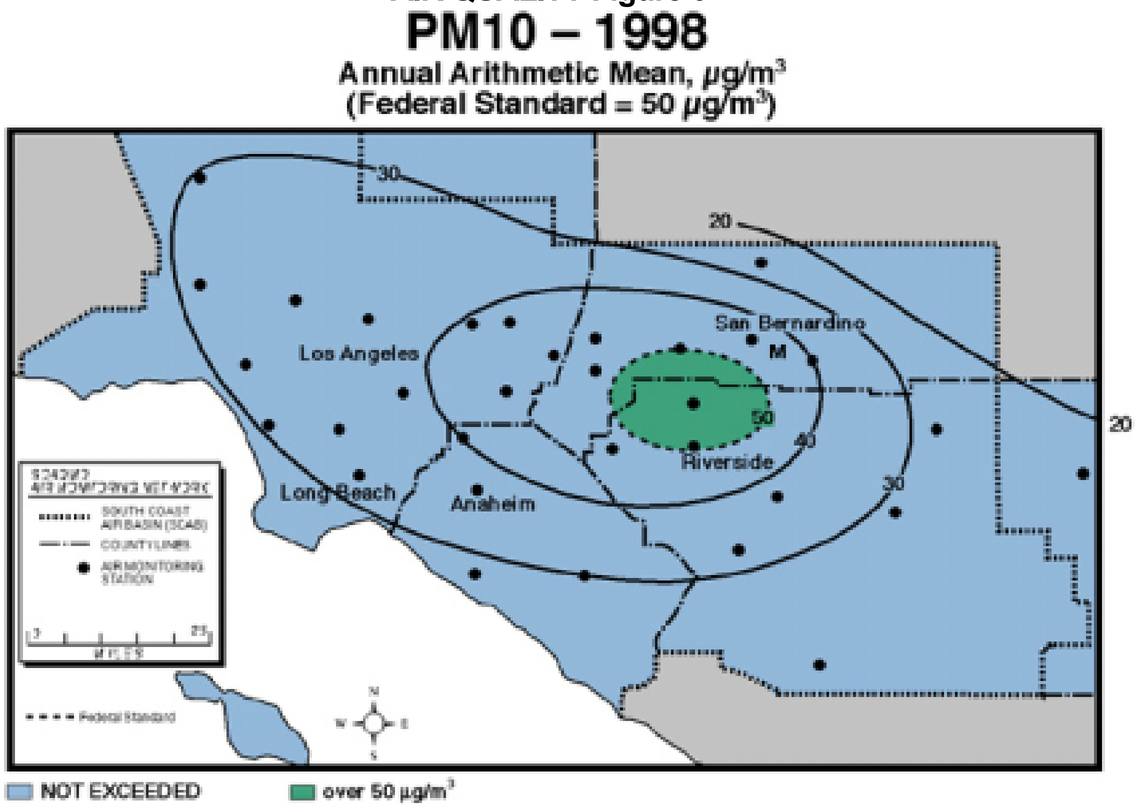
The transportation of ozone and ozone precursors from the South Coast air basin to the South Central Coast air basin is complicated by the existence of other transport couplings to the South Central Coast. The San Joaquin Valley air basin is classified as a significant contributor on some days and insignificant on others. The contributions from the California Coastal Waters (consisting of oil platforms and San Miguel, Santa Rosa and Santa Cruz Islands) are also considered significant on some days. Additionally there is a possibility that ozone transported within the inversion layer was tapped and may have been responsible for some of the ozone violations in the South Central Coast. In the November 1996, Second Triennial Review, CARB concludes that nine 1-hour ozone violations in Santa Barbara County (part of the South Central Coast) from 1994 to 1996 seemed to be related to transport from outside of the county. CARB classifies the South Coast contributions as significant on some days and inconsequential on others. However, CARB further classifies the nine violation days in Santa Barbara County as shared transport days.

For mitigation purposes, CARB requires two things of upwind air basins, a commitment to adopt best available retrofit control technologies for NOx and VOC emission sources and, for overwhelming transport, the inclusion of measures in the air quality plans to ensure expeditious attainment of the state 1-hour ozone standard in the downwind areas. SCAQMD Rule 1135 is a retrofit rule that applies to all electric power generating systems except those regulated by the RECLAIM program (Regulation XX). The RECLAIM program is considered a retrofit rule because it continually reduces the emission limits of NOx sources within the SCAQMD authority. The South Coast Air Quality Management Plan addresses attainment of the ***federal*** 1-hour ozone standard by the year 2010 for the SCAQMD only. However, the South Coast Air Quality Management Plan will have a positive and significant effect on the number and severity of violations of the 1-hour state ozone standard in downwind areas. Therefore, staff finds that the South Coast Air Quality Management Plan is well within the intent of the proposed CARB mitigation for upwind air basins.

AMBIENT PM10

PM10 is a particulate that is 10 microns in diameter or smaller that is suspended in air. PM10 can be directly emitted from a combustion source (primary PM10 or PM2.5) or soil disturbance (fugitive dust) or it can form downwind (secondary PM10) from some of the constituents of combustion exhaust (NOx, SOx and ammonia). San Bernardino (not the entire South Coast air basin) has been designated a non-attainment zone for the **federal** 24-hour and annual PM10 ambient air quality standards. The South Coast air basin (including a portion of the San Bernardino County within the basin) has been designated as a non-attainment zone for the **state** 24-hour and annual PM10 ambient air quality standards (see AIR QUALITY Table 2). AIR QUALITY Figure 6 shows the violations of the federal annual PM10 standard for 1998 in the South Coast air basin. The highest PM10 concentrations are occurring in both San Bernardino and Riverside Counties, as is shown in AIR QUALITY Figure 6. The project location is indicated by an **M** on AIR QUALITY Figure 6.

AIR QUALITY Figure 6



Source: 1998 Air Quality Standards Compliance Report, South Coast Air Quality Management District

AIR QUALITY Figure 7 shows the historic trend of 24-hour PM10 concentrations and the percent of samples (or measurements) that exceed the state and federal ambient air quality standards. As the figure shows, the 24-hour annual maximum measured concentrations have been significantly reduced from 1987 to 1999. Although violations of the state standard are still numerous, violations of the federal standard is coming under control for the South Coast air basin. The annual geometric mean[1] (state annual PM10 standard, 30 ug/m^3) and the annual arithmetic mean[2] (federal annual PM10 standard, 50 ug/m^3) are still well over their respective ambient air quality standards, even though they show improvement from 1987 to 1999 (see AIR QUALITY Figure 8).

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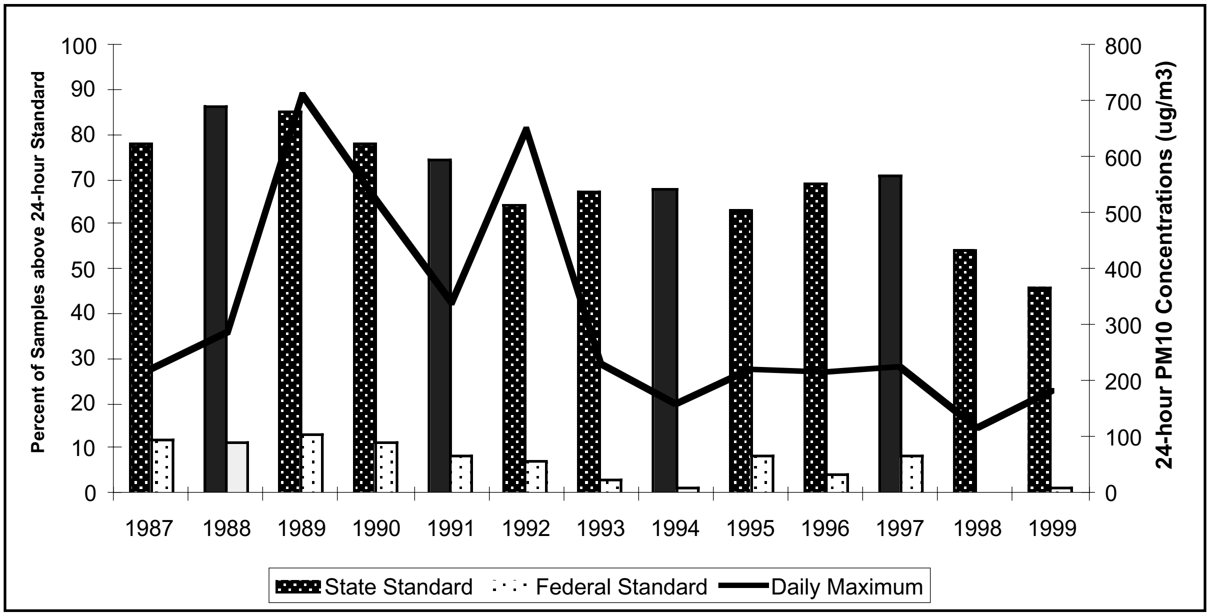
1 A geometric mean is the nth root of the product of n measurements.

2 An arithmetic mean is the sum of n measurements divided by n.

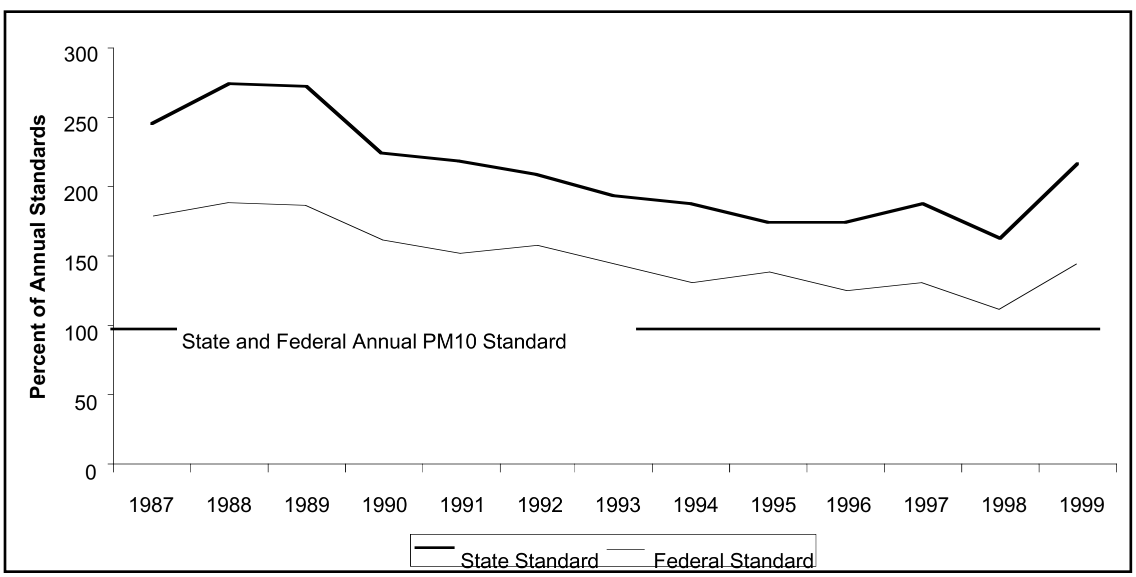
Note: Geometric means tend to generate a lower value than arithmetic means for the same set of measurements. This is because geometric means are less sensitive to extreme values.

AIR QUALITY Figure 7
Historic 24-hour PM10 Concentrations within the South Coast Air District
1987 to 1999



Source: California Air Resources Board

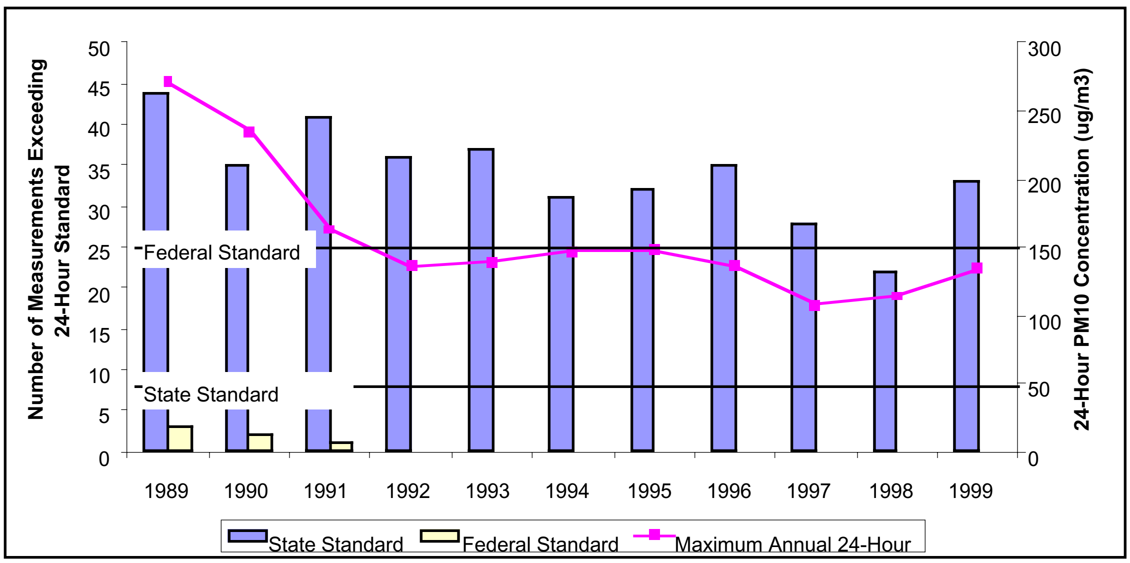
AIR QUALITY Figure 8
Historic Annual Average PM10 Concentrations in the South Coast Air Basin
1987 to 1999



Source: California Air Resources Board

AIR QUALITY Figure 9 shows the historic (1989 to 1999) 24-hour PM10 measurements made at the San Bernardino 4th street monitoring station. As can be seen, the federal 24-hour PM10 standard (150 ug/m^3) has not been exceeded since 1992 at this station, however the state 24-hour PM10 standard continues to be exceeded. The annual maximum 24-hour PM10 measurements at the 4th street monitoring station improved from 1989 to 1992, but appears to stabilize between 150 and 100 ug/m^3 with a slight downward trend there after. Therefore, staff recommends the use of the 1995 annual maximum 24-hour PM10 measurement recorded at the San Bernardino, 4th street monitoring station to represent the background 24-hour PM10 concentrations for modeling purposes. That measurement is 148 ug/m^3.

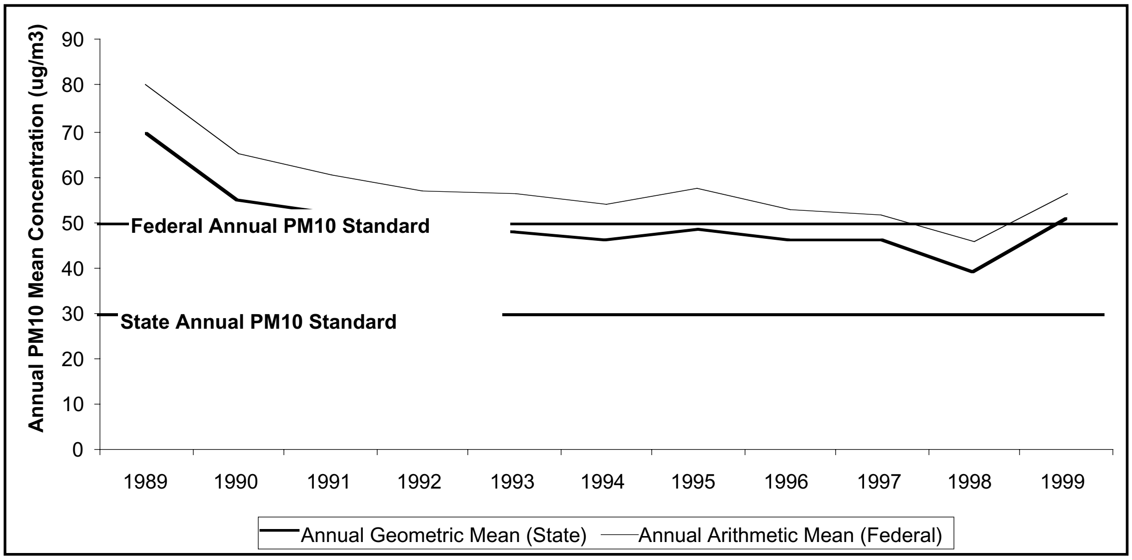
AIR QUALITY Figure 9
Historic 24-hour PM10 Measurements
San Bernardino, 4th Street Monitoring Station
1989 to 1999



Source: California Air Resources Board

AIR QUALITY Figure 10 shows the annual geometric and arithmetic means for the PM10 measurements at the San Bernardino 4th street monitoring station from 1989 to 1999. As can be seen, there is a notable improvement from 1989 to 1992, which stabilizes between 40 and 50 ug/m^3 with a slight downward trend there after. Since there is a significant jump in 1999 over the annual means recorded in 1998, staff recommends the use of the highest recent measurements to represent the annual PM10 background for modeling purposes. In staff s opinion the highest recent measurement for the arithmetic mean (federal standard) at the San Bernardino, 4th street monitoring station was in 57.3 ug/m^3 in 1995. The highest recent measurement for the geometric mean (state standard) at the same monitoring station was 50.6 ug/m^3 in 1999.

AIR QUALITY Figure 10
Historic Annual PM10 Measurements
San Bernardino, 4th Street Monitoring Station
1989 to 1999



Source: California Air Resources Board

SECONDARY PM10

PM10 can be formed downwind from an emission source as a secondary emission (similar to ozone) from a reaction between ammonia and airborne acids. The most dominant reactions are between SOx emissions (as sulfuric acid, H_2SO_4) and NOx emissions (as nitric acid, HNO_3). The complexity of these reactions arises from the formation of gaseous, liquid and solid forms of the products and reactants involved. The qualitative understanding of these reactions indicates that all the available ammonia will be reacted with all the available sulfuric acid prior to any ammonia being reacted with any available nitric acid (Seinfeld 1986). From this presumption, two cases of interest arise. The sulfate rich case, where the molar ratio of ammonia (NH_3) to sulfate (SO_4) is less than 2, so that there is insufficient ammonia to react with the sulfate. The ammonia rich case, where the molar ratio of ammonia to sulfate is greater than 2, so that the sulfate is completely reacted and there is excess ammonia (Seinfeld 1986).

The nitrate reaction with ammonia is an equilibrium reaction between the reactants (ammonia and nitric acid) in gaseous form and the product (ammonium nitrate) in solid or aqueous form (Seinfeld 1986). To determine if ammonia nitrate (NH_4NO_3) will be formed, the product of the total nitrate (HNO_3 + NO_3^-, TN) and total ammonia (NH_3 + NH_4^+, TA) available is compared to the equilibrium dissociation constant (K_p) for pure ammonium nitrate at the ambient temperature and relative humidity (Seinfeld 1986). If the resulting product (TN*TA) is greater than K_p then ammonium nitrate should form (Seinfeld 1986). If ammonia, nitric acid and ammonium nitrate can be measured in the area of interest then it can be presumed that the product (TN*TA) is greater than K_p and that the reaction is occurring. Assuming conservation of total ammonia and nitrate, ammonium nitrate (AN) can be estimated (see Appendix A for complete calculations).

For the purpose of determining the secondary PM10 potential impacts it is necessary to determine first if the area is either ammonia rich or sulfate rich as discussed above.   Then second, to determine what additional ammonium sulfate and ammonium nitrate are likely to form. Lastly, those impacts must be compared to the existing background measurements that are available. Therefore, for these purposes only, staff presents background ambient air quality measurements for ammonia, nitric acid, nitrate and sulfate.

Ammonia and nitric acid are not typically measured in the South Coast air basin, however a 1995 study regarding dairy emissions included ambient measurements of ammonia and nitric acid for several specific days. The nearest measurements taken were at the Fontana monitoring station in San Bernardino County and the Rubidoux monitoring station in Riverside County. The 1995 study also included the annual average ammonia and nitric acid concentrations at Fontana and Rubidoux. AIR QUALITY Table 3 shows the maximum measured ammonia concentration and the annual average concentrations of ammonia and nitric acid. Since no further information in available on ammonia or nitric acid ambient air concentrations, staff recommends the values in AIR QUALITY Table 3 to represent the environmental background for ammonia and nitric acid.

AIR QUALITY Table 3
Ammonia and Nitric Acid Concentrations
Fontana and Rubidoux
South Coast Air District — 1995

Monitoring Site	Maximum Ammonia Concentration (ug/m^3)	Annual Ammonia Concentration (ug/m^3)	Annual Nitric Acid Concentration (ug/m^3)
Fontana[1]	25.93	13	2.9
Rubidoux[2]	25.43	39	0.9
1 Measured November 16, 1995 2 Measured November 17, 1995			

Source: 1995 Dairy Emissions Study, South Coast Air Quality Management District

Nitrate and sulfate ambient air measurements are also available at the Fontana and Rubidoux monitoring stations (from 1986 to 1999). The available data suggests that, while the maximum nitrate and sulfate concentrations fluctuate significantly over time, the annual averages show a slight, although steady, improvement. This may be in response to the improved ozone concentrations or to changing agriculture and industrial activities. To be consistent with the 1995 dairy study, staff recommends using the 1995 nitrate and sulfate ambient air quality data reported at Fontana and Rubidoux (see AIR QUALITY Table 4) for the same days the study was performed (as noted in AIR QUALITY Table 3).

AIR QUALITY Table 4
Sulfate and Nitrate Concentrations
Fontana and Rubidoux
South Coast Air District — 1995

Monitoring Stations	Maximum Concentration (ug/m^3)	Annual Average Concentration (ug/m^3)
Sulfate		
Fontana	2.7[1]	4.03
Rubidoux	3.6[1]	4.81
Nitrate		
Fontana	24.6[1]	6.9
Rubidoux	30.9[1]	11.69
1 Measurements taken on November 19, 1995		

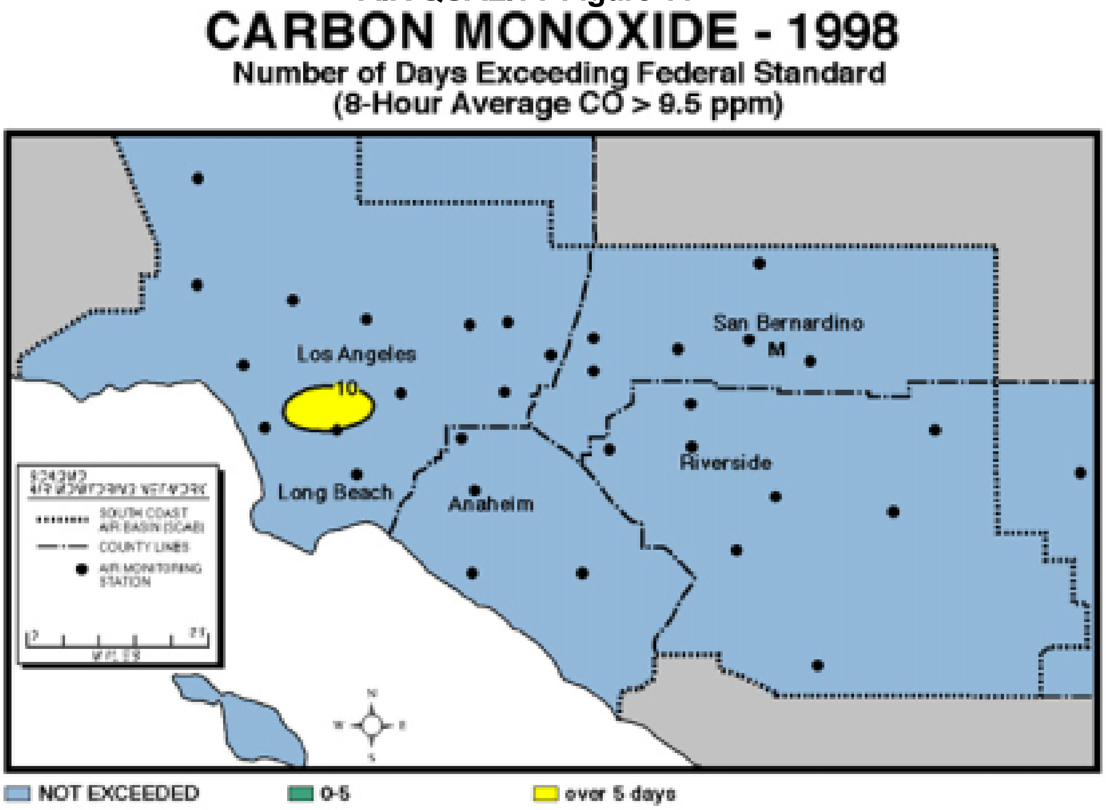
Source: California Air Resources Board

Dividing the annual average ammonia concentrations by the annual average sulfate concentrations at both monitoring stations results in a ratio of 3.22 for Fontana and 8.11 for Rubidoux. Therefore, as discussed earlier, the area would be considered ammonia rich (ie., the ammonia to sulfate ratio is greater than 2:1). On November 16 and 17 of 1995, the maximum concentrations of ammonia were measured at the Fontana and Rubidoux monitoring stations respectively (see AIR QUALITY Table 3). Comparing these to the closest sulfate concentrations at those stations (measured on November 19, 1995), results in a ratio of 9.60 for Fontana and 7.06 for Rubidoux. Therefore, it is staff s recommendation to conclude that the area near the proposed power plant site is ammonia rich.

CARBON MONOXIDE

Carbon monoxide (CO) is a directly emitted air pollutant as a result of combustion. The South Coast Air Quality Management District is designated Serious Non-Attainment for the federal 1-hour and 8-hour CO ambient air quality standards. This means that the area has an average CO concentration value of 16.5 ppm or above. However, as AIR QUALITY Figure 11 shows, the exceedences of the federal CO standard occur in Los Angles County which is a considerable distance from the project site. San Bernardino County (including the portion in the SCAQMD) is designated attainment for the state 1-hour and 8-hour ambient air quality standards.

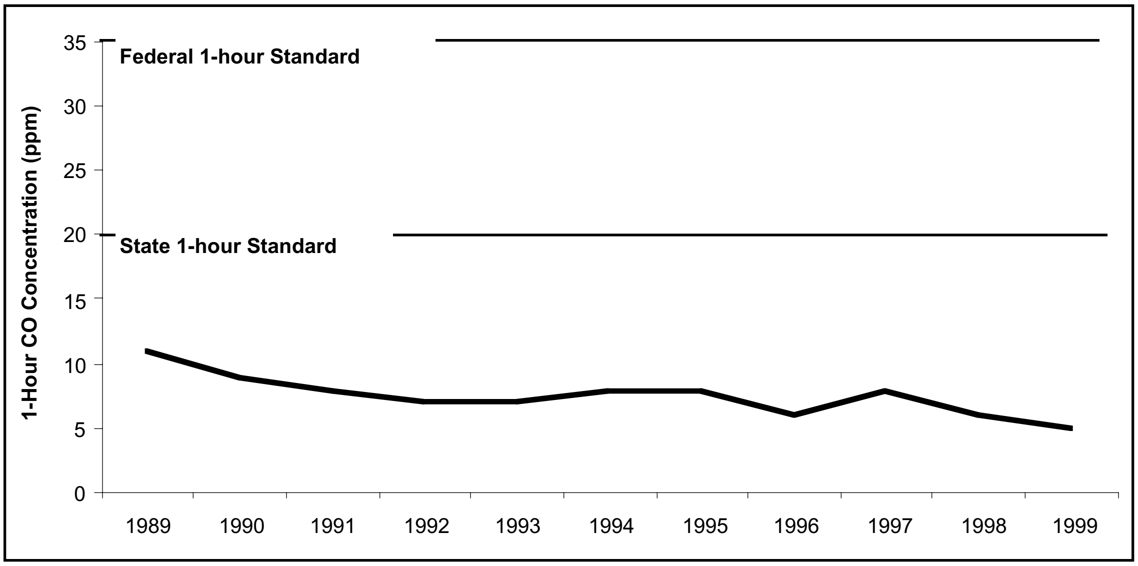
AIR QUALITY Figure 11



Source: 1998 Air Quality Standards Compliance Report, South Coast Air Quality Management District

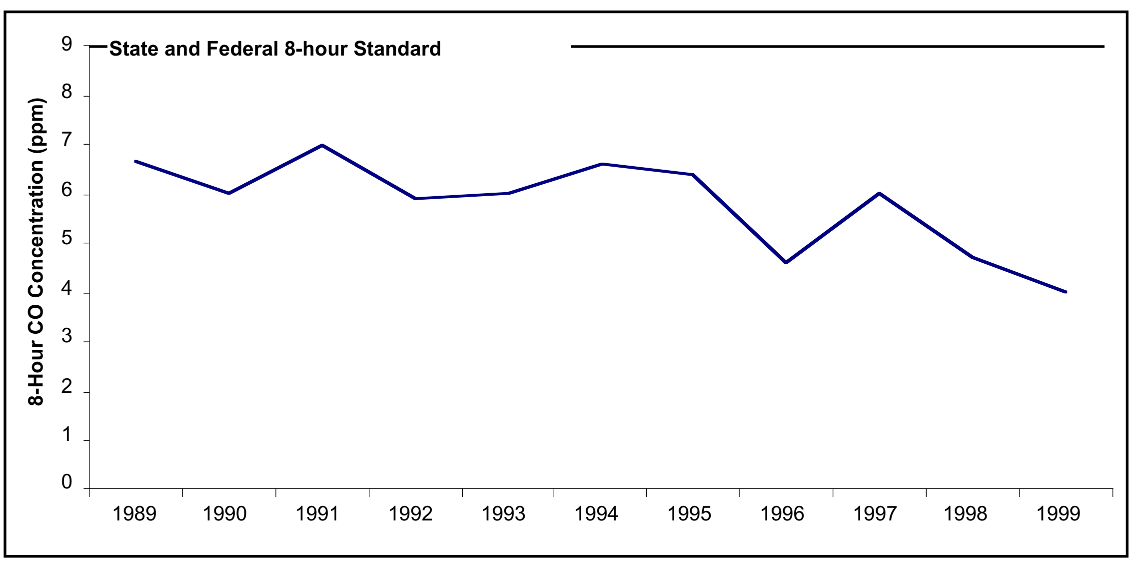
The closest CO monitoring station to the project site is the San Bernardino station. AIR QUALITY Figures 12 and 13 show the historical CO concentrations at the San Bernardino monitoring station. These figures demonstrate a slight downward trend from 1989 to 1999. Therefore staff recommends the lowest value be used for the background CO concentrations for air quality impact modeling purposes. For both the 1-hour and 8-hour standards, this is the 1999 measurement of 5 ppm and 4.0 ppm respectively.

AIR QUALITY Figure 12
Historical 1-Hour CO Concentrations
San Bernardino, 4th Street Monitoring Station
1989 to 1999



Source: California Air Resources Board

AIR QUALITY Figure 13
Historical 8-Hour CO Concentrations
San Bernardino, 4th Street Monitoring Station
1989 to 1999

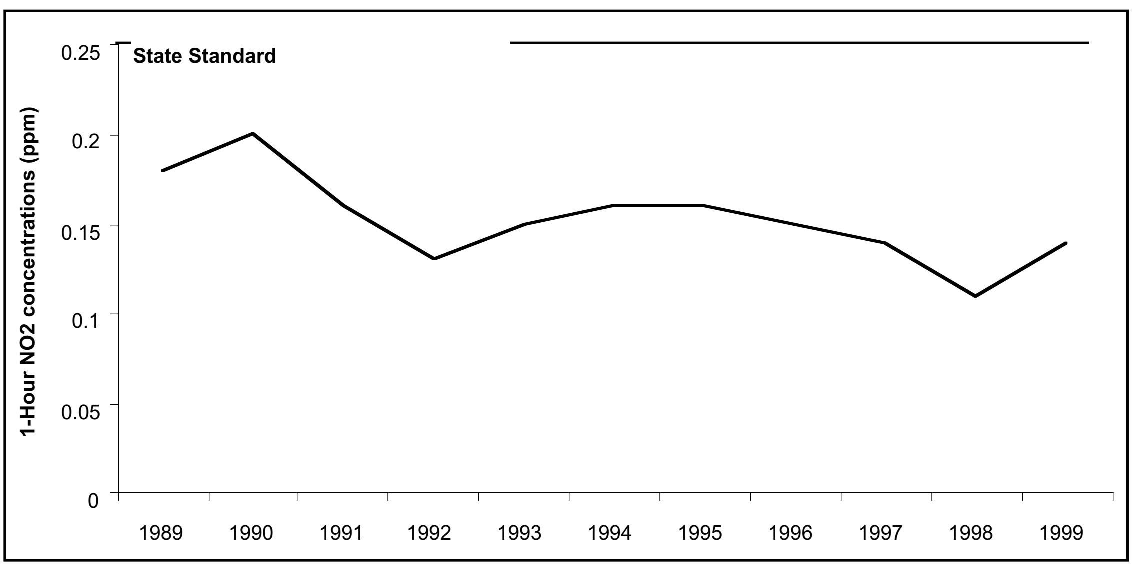


Source: California Air Resources Board

NITROGEN DIOXIDE

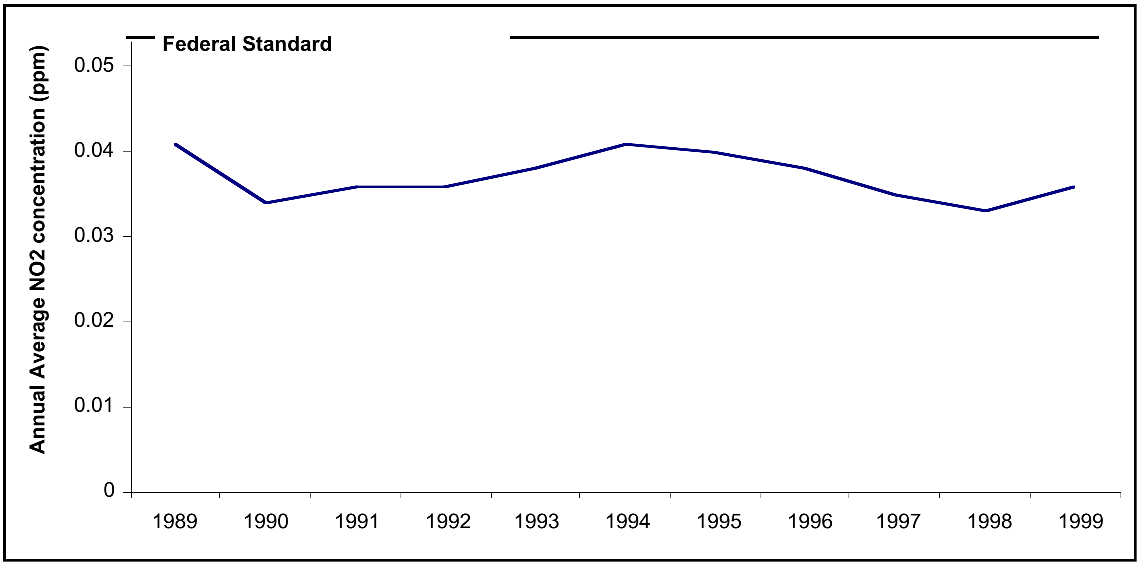
Nitrogen dioxide (NO2) can be emitted directly as a result of combustion or formed from nitric oxide (NO) and oxygen. NO is typically emitted from combustion sources and readily reacts with oxygen or ozone to form NO2. The NO reaction with ozone can occur within minutes and is typically referred to as ozone scavenging. By contrast, the NO reaction with oxygen is on the order of hours under the proper conditions. The South Coast Air Basin is designated attainment for both the state and federal NO2 ambient air quality standards. AIR QUALITY Figures 14 and 15 show the 1-hour and annual NO2 concentrations measured at the San Bernardino monitoring station, the closest NO2 monitoring station to the project site. These figures show a slight, but erratic improvement in NO2 concentrations from 1989 to 1999. Staff therefore recommends that the 1999 measurements be used as they represent reasonably higher values and are the most recent. The 1-hour and annual average NO2 concentrations measured at the San Bernardino monitoring station in 1999 are 0.14 ppm and 0.0358 ppm respectively.

AIR QUALITY Figure 14
Historical 1-Hour NO_2 Concentrations
San Bernardino, 4th Street Monitoring Station
1989 to 1999



Source: California Air Resources Board

AIR QUALITY Figure 15
Historical Annual Average NO_2 Concentrations
San Bernardino, 4th Street Monitoring Station
1989 to 1999

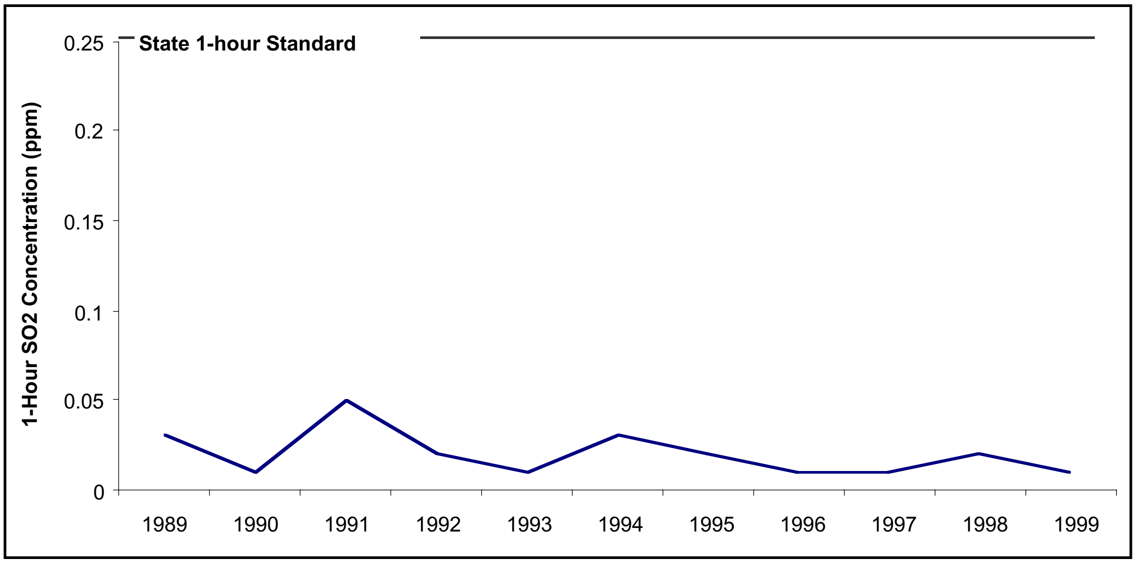


Source: California Air Resources Board

SULFUR DIOXIDE

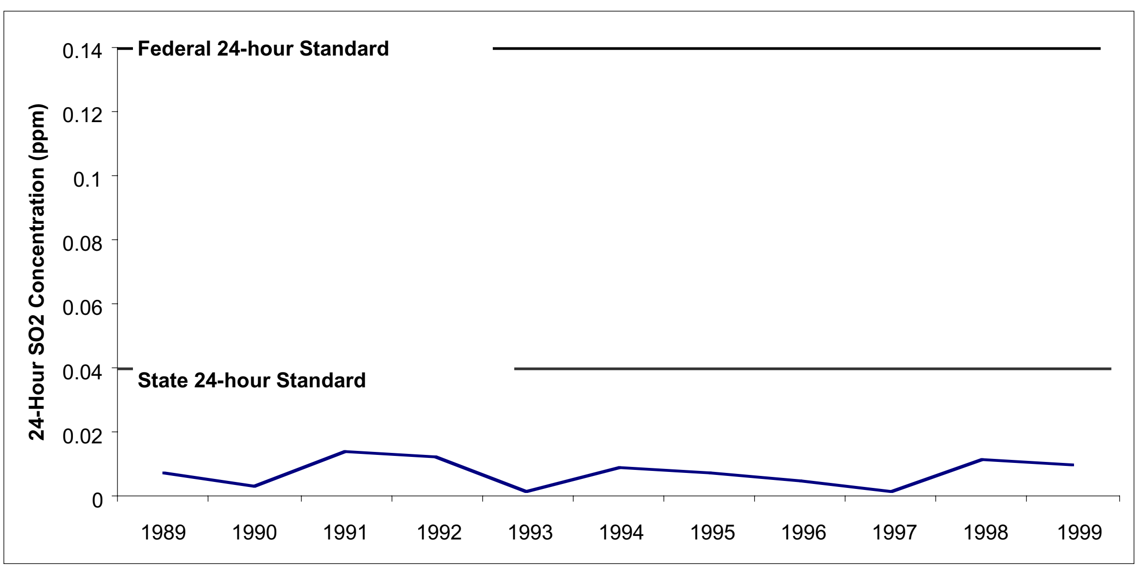
Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. Fuels such as natural gas contain very little sulfur and consequently have very low SO2 emissions when combusted. By contrast fuels high in sulfur content such as lignite (a type coal) emit very large amounts of SO2 when combusted. Sources of SO2 emissions within the South Coast Air District come from every economic sector and include a wide variety of fuels, gaseous, liquid and solid. The South Coast air basin is designated attainment for all the SO2 state and federal ambient air quality standards. The closest SO2 monitoring station to the project site is in Fontana on Arrow Hwy. AIR QUALITY Figures 16, 17 and 18 show the historic 1-hour, 24-hour and annual average SO2 concentrations measured at the Fontana monitoring station. These figures show that the concentrations of SO2 are far below the state and federal SO2 ambient air quality standards. However, the trends are ambiguous and indicate neither an increase nor a decrease in SO2 concentrations. Therefore staff recommends the highest concentrations within the last 5 years be used to represent the background for SO2 for modeling purposes. For the 1-hour standard, this is 0.02 ppm (measured in 1998). For the 24-hour standard, 0.011 ppm (1998). For the annual standard, 0.0018 (1999).

AIR QUALITY Figure 16
Historical 1-Hour SO_2 Concentrations
Fontana, Arrow Highway Monitoring Station
1989 to 1999



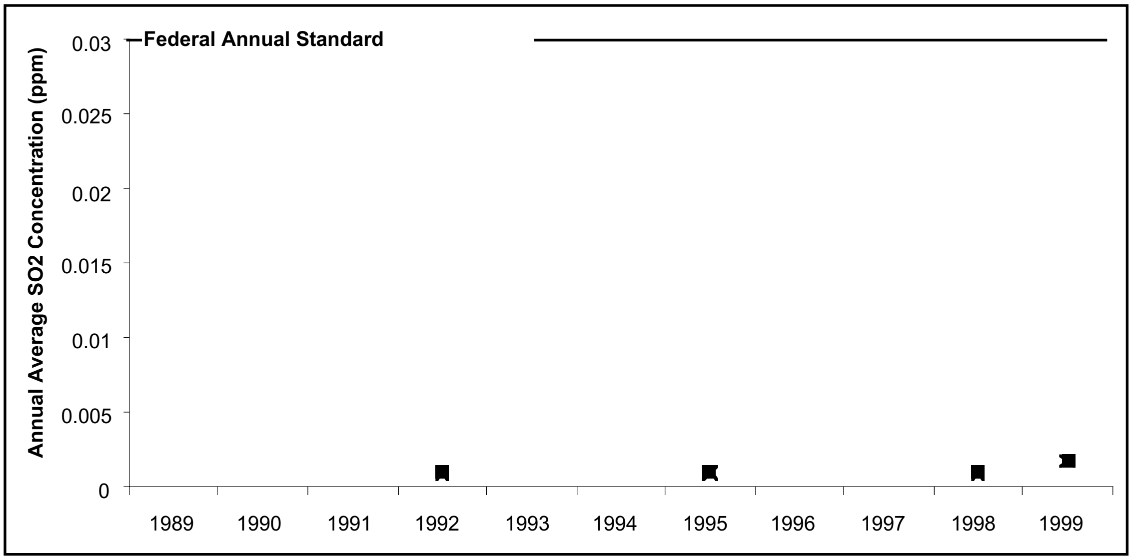
Source: California Air Resources Board

AIR QUALITY Figure 17
Historical 24-Hour SO_2 Concentrations
Fontana, Arrow Highway Monitoring Station
1989 to 1999



Source: California Air Resources Board

AIR QUALITY Figure 18
Historical Annual Average SO_2 Concentrations
Fontana, Arrow Highway Monitoring Station
1989 to 1999



Source: California Air Resources Board

SUMMARY

In summary staff recommends the background ambient air concentrations in AIR Quality Table 5 for the purpose of modeling and evaluating potential ambient air quality impacts from the proposed project.

AIR QUALITY Table 5
Staff Recommended Background Concentrations

Pollutant	Averaging Time	Concentration (ug/m^3)	Concentration (ppm)
Ozone	1 Hour	332.9	0.17
Particulate Matter	Annual Geometric Mean	50.6	--
	Annual Arithmetic Mean	57.3	--
	24 Hour	148	--
	Annual Ammonia	39	--
	Annual Nitric Acid	2.9	--
	Annual Sulfate	4.81	--
	Annual Nitrate	11.69	--
Carbon Monoxide	8 Hour	4,444	4.0
	1 Hour	5,750	5
Nitrogen Dioxide	Annual Average	67.54	0.0358
	1 Hour	263.2	0.14
Sulfur Dioxide	Annual Average	4.8	0.0018
	24 Hour	28.9	0.011
	1 Hour	52.4	0.02

PROJECT DESCRIPTION AND EMISSIONS

CONSTRUCTION

The MVPP will construct or modify the following major elements at the project site:

- The addition of four General Electric Frame 7FA gas fired combustion turbines with duct fired heat recovery steam generators (HRSG) driving two steam turbines, arranged into two 2-on-1 systems (referred to as units 3 and 4).
- The addition of two new 10-cell (0.0006 drift rate) cooling towers in a 2x5 configuration serving the new turbines.
- The replacement of existing cooling towers serving the existing boiler units (referred to as units1 and 2) with two new 4-cell (0.0006 drift rate) cooling towers.
- The addition of a new 182 Bhp diesel fired firewater pump.
- The addition of a new 5,900 Bhp diesel fired emergency generator.
- Modification of the existing switch yard including the expansion of the bus bar system, additional circuit breakers, expansion of the ground cable system and additional power line towers.

The MVPP will construct the following linear ancillary service projects off the project site:

- The natural gas line will be 24 to 30 inches in diameter and 17 miles long.
- The proposed water pipeline is 2.3 miles long and 12 to 16 inches in diameter, however the water supply has not been confirmed at this time.
- A wastewater brine pipeline is 12 inches in diameter and 1,100 feet long.

Construction activities, on or off site, will generate air emissions from earth moving activities and construction equipment. On-site construction is expected to last 19 months with the highest fugitive emissions occurring in the second month and the highest overall emissions occurring in the seventh month. Offsite construction is expected to be completed much faster than on-site construction, on the order of six months.

MVPC proposes to implement the following measures to reduce emissions during construction activities. The emission estimates from MVPC that follow this section take these control measures into consideration.

To control exhaust emissions from heavy diesel construction equipment:

- Limit engine idle time and shutdown equipment when not in use (although a specific time limit was not indicated).
- Perform regular preventative maintenance to reduce engine problems.
- Use CARB Low-Sulfur fuel for all heavy construction equipment.

- Ensure that all heavy construction equipment complies with EPA 1996 Diesel standards.

To control fugitive dust emissions:

- Use water application or chemical dust suppressant on unpaved travel surfaces and parking areas.
- Use vacuum or water flushing on paved travel surfaces and parking areas.
- Require all trucks hauling loose material to either cover or maintain a minimum of two feet of freeboard.
- Limit traffic speed on unpaved roads to 25 mph.
- Install erosion control measures.
- Re-plant disturbed areas as soon as possible.
- Use gravel pads and wheel washers as needed.
- Use wind breaks and chemical dust suppressant or water application to control wind erosion from disturbed areas.

PROJECT SITE

The power plant itself will take approximately 19 months to construct. The power plant project construction consists of three major areas of activity: 1) the civil/structural construction 2) the mechanical construction, and 3) the electrical construction. The largest fugitive dust emissions are generated during the civil/structural activity, where work such as demolition, grading, site preparation, foundations, underground utility installation and building erection occur. These types of activities require the use of large earth moving equipment, which generate considerable combustion emissions themselves, along with creating fugitive dust emissions. The mechanical construction includes the installation of the heavy equipment, such as the combustion and steam turbines, the heat recovery steam generators, condenser, pumps, piping and valves. Although not a large fugitive dust generation activity, the use of large cranes to install such equipment generates significantly more emissions than other construction equipment onsite. Finally, the electrical equipment installation occurs involving such items as transformers, switching gear, instrumentation and wiring. This is a relatively small emissions generating activity in comparison to the early construction activities. From estimates made by MVPC, the emissions from the seventh month of construction are significantly higher than those from the second month with the exception of fugitive dust emissions. The MVPC estimates for the highest daily emissions, based on the seventh month emissions are shown in AIR QUALITY Table 6. AIR QUALITY Table 6 also shows the expected daily emission totals based on the second month of construction. As can be seen, the fugitive dust emissions are significantly higher for the second month than the seventh even though the rest of the criteria pollutants are far lower. AIR QUALITY Table 7 shows the expected annual emissions from construction activities at the project site.

AIR QUALITY Table 6
Maximum Daily On-site Construction Emissions (lbs/day)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Construction Equipment	257.49	35.38	368.00	8.49	16.26	10.82
Truck Deliveries [1]	27.28	2.81	19.98	1.43	1.59	0.11
Rail Deliveries	83.93	3.11	8.27	5.36	2.08	2.60
Worker Travel [1]	65.67	73.21	671.81	0.08	2.21	0.38
Windblown Dust [2]	–	–	–	–	–	14.86
Total [3]	434.37	114.51	1,068.06	15.36	22.14	28.77
Emissions from second month of construction	171.14	50.18	479.30	5.00	10.28	41.60

1 Includes both paved and unpaved road travel

2 Includes emissions from the active construction area, laydown area and contractor parking.

3 Emission totals for the seventh month of construction.

Source: (MVPC 2000ff)

AIR QUALITY Table 7
Annual On-site Construction Emissions (tons/year)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Construction Equipment	13.25	1.81	18.52	0.42	0.88	2.54[1]
Truck Deliveries [1]	3.44	0.36	2.52	0.18	0.20	–
Rail Deliveries	3.55	0.13	0.35	0.23	0.09	–
Worker Travel [1]	8.81	9.82	90.14	0.01	0.30	–
Windblown Dust [2]	–	–	–	–	–	2.71
Total	29.05	12.12	111.53	0.84	1.47	5.25

1 Includes construction, truck deliveries, train deliveries and worker travel.

2 Includes emissions from the active construction area, laydown area and contractor parking.

Source: (MVPC 2000ff)

LINEAR FACILITIES

The linear facilities include the natural gas pipeline, the water supply pipeline and the wastewater pipeline. The construction of all linear facilities is not expected to last longer than six months.

The natural gas pipeline will be a new 17-mile long line from the Southern California Gas line 4000/4002 near Etiwanda Avenue in the city of Rancho Cucamonga. The natural gas pipeline will be laid entirely within the existing right-of-ways of city streets and will enter the power plant site from San Bernardino Avenue. The natural gas pipeline construction will include a new metering station and gas compressors at the project site. The natural gas pipeline will be buried with a minimum cover of 36 inches along the entire route. Trenching will be done in 500 foot increments, except when horizontal drilling is required. AIR QUALITY Table 8 shows the maximum daily emissions expected from the construction of the natural gas pipeline.

AIR QUALITY Table 8
Maximum Daily Natural Gas Pipeline Construction Emissions (lbs/day)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Construction Equipment	56.2	4.0	17.5	1.9	3.3	0.54
Truck Deliveries	14.29	1.47	10.47	0.75	0.83	0.06
Excavation	–	–	–	–	–	1.22
Back Filling	–	–	–	–	–	0.08
Windblown Dust	–	–	–	–	–	0.02
Total	70.49	5.47	27.97	2.65	4.13	1.92

Source: (MVPC 2000ff)

The current proposal for the water supply to the new facility is to use existing and new wells on the power plant site in addition to reclaimed water from the City of Redlands water treatment plant, which would require a water pipeline approximately 2.3 miles long. The water supply pipeline would be buried in a trench approximately 24 inches wide and ranging in depth from 60 to 90 inches. MVPC proposes to excavate 100-foot sections of the water supply pipeline at a time except where horizontal drilling is required. AIR QUALITY Table 9 shows the maximum daily emissions expected from the construction of the water supply line.

AIR QUALITY Table 9
Maximum Daily Water Supply Pipeline Construction Emissions (lbs/day)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Construction Equipment	47.5	3.1	11.2	1.4	2.8	0.11
Truck Deliveries	7.15	0.74	5.23	0.38	0.42	0.01
Excavation	–	–	–	–	–	0.11
Back Filling	–	–	–	–	–	0.01
Windblown Dust	–	–	–	–	–	0.00
Total	54.65	3.84	16.43	1.78	3.22	0.24

Source: (MVPC 2000ff)

The wastewater pipeline will be 12 inches in diameter and will connect an existing water pipeline on the project site to an existing Santa Ana River Industrial (SARI) discharge line. This line ultimately runs to the Orange County Sanitation District s Fountain Valley Wastewater Treatment facility, where the wastewater is treated prior to discharge to the Pacific Ocean. The new connecting pipeline will be buried with a minimum cover of 36 inches in most locations. At other locations the wastewater pipeline will be attached to existing bridges to cross waterways. The construction of the wastewater pipeline is not expected to last more than two months. AIR QUALITY Table 10 shows the maximum daily emissions from the construction of the wastewater pipeline.

AIR QUALITY Table 10
Maximum Daily Wastewater Pipeline Construction Emissions (lbs/day)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Construction Equipment	22.1	1.6	7.5	0.8	1.3	0.03
Truck Deliveries	3.57	0.37	2.62	0.19	0.21	0.00
Excavation	–	–	–	–	–	0.02
Back Filling	–	–	–	–	–	0.00
Windblown Dust	–	–	–	–	–	0.00
Total	25.67	1.97	10.12	0.99	1.51	0.05

Source: (MVPC 2000ff)

OPERATIONAL PHASE

EQUIPMENT DESCRIPTION

The equipment at the MVPP will consist of the following components:

- Four natural gas fired General Electric Frame 7FA combustion turbine generators (CTG), nominally rated at approximately 175 MW. Each of the CTGs will be equipped with evaporative inlet air coolers;
- Each CTG would be equipped with gas fired heat recovery steam generators (HRSG) and ancillary equipment;
- Two steam turbine, rated at approximately 200 MW;
- Two ten-cell cooling towers with 0.0006% drift rates for the new CTGs;
- Two four-cell cooling towers with 0.0006% drift rates for the existing boilers;
- One 182 Bhp diesel fired firewater pump;
- One 5,900 Bhp diesel fired emergency engine;
- Two existing gas fired boilers-steam turbine pairs, rated at 69 MW each.

EQUIPMENT OPERATION

The MVPP is intended to be a base loaded power plant with the capability to respond to market demands. The two boilers (units 1 & 2) and the four CTGs (units 3 & 4) will operate exclusively on natural gas. The 182 Bhp firewater pump and the 5,900 Bhp emergency IC engine will operate exclusively on diesel fuel. For clarification purposes, it is important to understand that the existing boilers (units 1 and 2) are considered to be part of the new facility. The operations at the existing boilers are proposed to be increased and are coupled with a change in emission controls and a net increase in emissions.

EMISSION CONTROLS

The exclusive use of an inherently clean fuel, natural gas, will limit the formation of SO2 and PM10 emissions. Natural gas contains very small amounts of a sulfur compound known as mercaptan, which when combusted, results in sulfur dioxide emissions in the flue gas. However, in comparison to other fuels used in power plants, such as fuel oil or coal, the sulfur dioxide emissions from the combustion of natural gas are very low.

Like SO2, the emissions of PM10 from natural gas combustion are very low compared to the combustion of fuel oil or coal. Natural gas contains very little noncombustible gas or solid residue; therefore it is a relatively clean-burning fuel. A sulfur content of 0.75 grains of sulfur per 100 standard cubic feet of natural gas was assumed for the SO2 emission calculations.

To minimize NOx, CO and VOC emissions during the combustion process, the CTGs are equipped with the latest dry low-NOx combustor design developed by

GE. A more detailed discussion of this combustion technology is presented in the Mitigation section of this analysis.

After combustion, the flue gases pass through the natural gas fired heat recovery steam generator (HRSG), where catalyst systems are placed to further reduce NOx, CO and VOC emissions. MVPC is proposing to use a Selective Catalytic Reduction (SCR) system to reduce NOx emissions. An oxidizing catalyst, will also be installed in the HRSG to reduce CO and VOC emissions. A more complete discussion of these catalyst technologies is included in the Mitigation section.

The existing boilers (units 1 and 2) will be retrofitted with water injection and possibly overfire air modifications or an ammonia injection system to control the formation of NOx emissions.

PROJECT OPERATING EMISSIONS

The air emissions associated with the MVPP are shown in AIR QUALITY Tables 11 and 12. Table 11 shows the emission rates for the GE Frame 7FA turbines equipped with DLN combustors, SCRs and oxidation catalysts. Table 11 also shows the estimated emission rates for the boilers (from recent source testing), the cooling towers (two towers for the boiler systems and two towers for the four turbines), the emergency IC engine and the firewater pump. AIR QUALITY Table 12 shows the emission rates for the turbines at various ambient temperatures and with or without the HRSG duct firing natural gas. The emission rates in AIR QUALITY Table 12 are used to calculate the long-term annual average emissions for the MVPP. The short-term (hourly through daily) emissions are calculated using the emission rates in AIR QUALITY Table 11. The NOx and CO emission rates shown in AIR QUALITY Table 12 assume that the MVPP will average (on an annual basis) a lower concentration than that used for the short-term emission rates. For NOx, the short-term emission rates are based on a 2.5 ppm concentration limit, the long-term emission rates are based on 1.0 ppm concentration limit. For CO, the short-term emission rates are based on a 6.0 ppm concentration limit and the long-term emission rates are based on a 2.0 ppm concentration limit. Since both NOx and CO emissions will be continuously monitored in the stack (see compliance with LORS section), making this assumption is reasonable and enforceable.

AIR QUALITY Table 11
Short-Term Estimated Emission Rates
(lbs/hour)

Equipment	Operation	NOx	SOx	CO	VOC	PM10
Turbine	Full Load[1]	16.59	1.32	24.20	3.24	11.00
	Full Load[2]	17.77	1.42	25.91	3.47	11.00
	Cold Startup	20.00	0.86	50.00	3.47	10.38
	Warm Startup	20.00	0.86	62.50	3.47	10.38
	Hot Startup	20.00	0.86	100.0	3.47	10.38
10-Cell Cooling Tower[3]	Full Load					2.92
	Startup					2.92
Existing Boiler	Full Load	32.64	0.68	2.04	0.68	0.20
	Startup	2.51	0.05	0.16	0.05	0.02
4-Cell Cooling Tower[4]	Full Load					0.77
	Startup					0.06
Emergency IC Engine	Full Load	19.80	0.44	1.56	1.56	0.81
Firewater Pump	Full Load	1.98	0.063	0.53	0.31	0.10

1 The turbine is at full load in 30 °F ambient air temperature without duct firing.
2 The turbine is at full load in 30 °F ambient air temperature with duct firing.
3 There are two 10-cell cooling towers associated with the turbines for heat rejection.
4 There are two 4-cell cooling towers associated with the boilers for heat rejection.

Source: (MVPC 2000a)

AIR QUALITY Table 12
Estimated Turbine Annual Average Hourly Emission Rates
(lbs/hour)

Temperature (°F)	Duct Firing	NOx[1]	SOx	CO[2]	VOC	PM10
102	On	6.56	1.31	7.98	3.19	11
82	On	6.66	1.33	8.11	3.24	11
59	Off	6.38	1.28	7.8	3.12	11
59	On	Na[3]	1.37	8.34	3.34	11
30	Off	6.62	1.32	8.06	3.24	11
30	On	7.13	1.42	8.65	3.47	11

1 The NOx emission rates assume that the MVPP can achieve 1.0 ppm averaged over the entire year.
2 The CO emission rates assume that the MVPP can achieve 2.0 ppm averaged over the entire year.
3 The NOx emission rate for 59 °F with duct firing is not proposed to be used to calculate any longterm NOx emissions or impacts.

Source: (MVPC 2000a)

STARTUP

The MVPP has four general startup scenarios, black start, cold start, warm start and hot start. Black starting means that the power plant starts with no power from the grid. MVPC has stated that they will first start the emergency IC engine, then start the existing boilers (units 1 and 2) and finally start the combustion turbines (units 3 and 4). Black starting is a very unusual situation and is not expected to occur in the lifetime of the facility. Additionally, it is unusual to black start boilers, as opposed to black starting the turbines. Black starting the boilers requires a significant amount of power for the compressors, pumps and other associated equipment. That is why the IC engine is rated at 5,900 Bhp, which is unusually large. Black starting the turbines (one set at a time) maybe more complex for the facility as a whole, but it would relieve the facility of the need to use such a large IC engine (more along the lines of 500-1,000 Bhp). However, staff is unaware of any other facility in the United States that has both boilers and turbines operating together at such a high total facility capacity in conjunction with black start capability. Given that the boilers, once started, would likely be the most stable power producing equipment at the facility (as opposed to the turbines, which are easier to knock back offline during this process), staff has no objection to black starting the boilers prior to the turbines.

The emissions associated with black starting are very high because the generating equipment starts from a cold status. The duration of a black startup can exceed 9 hours for this facility due to the sequence of starts. Staff assumes that the boilers in this situation are relatively warm and can be re-started in three hours. Staff then follows the assumptions of cold startup (see below). Both turbines of unit 3 will startup at the same time, three hours later both turbines of unit 4 will begin their startup (for a total startup duration of six hours). During the time that the turbines are in startup, the boiler units will both be assumed at full load. AIR QUALITY Table 13 shows the likely emissions from black starting at the MVPP facility. Because black starting is an extremely unlikely event, staff will not further analyze this operational scenario.

AIR QUALITY Table 13
Black Startup Emission Estimate
(pounds per event)

Equipment	Operation	Duration (hours)	NOx	SOx	CO	VOC	PM10
Emergency Engine	Full Load	3	59.40	1.32	4.68	4.68	2.43
Boiler Unit 1	Startup	3	7.53	0.15	0.48	0.15	0.06
Boiler Unit 2	Startup	3	7.53	0.15	0.48	0.15	0.06
4-Cell Tower[1] Unit 1	Startup	3	--	--	--	--	0.18
4-Cell Tower[1] Unit 2	Startup	3	--	--	--	--	0.18
Boiler Unit 1	Full Load	6	195.84	4.08	12.24	4.08	1.20
Boiler Unit 2	Full Load	6	195.84	4.08	12.24	4.08	1.20
4-Cell Tower[1] Unit 1	Full Load	6	--	--	--	--	4.62
4-Cell Tower[1] Unit 2	Full Load	6	--	--	--	--	4.62
Unit 3 Turbine 1	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 2	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 1	Full Load[2]	3	49.77	3.96	72.60	9.72	33.00
Unit 3 Turbine 2	Full Load[2]	3	49.77	3.96	72.60	9.72	33.00
Unit 4 Turbine 1	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 4 Turbine 2	Startup	3	60.00	2.58	150.00	10.41	31.14
10-Cell Tower[3] Unit 1	Full Load[4]	6[5]	--	--	--	--	17.52
10-Cell Tower[3] Unit 2	Full Load[4]	3	--	--	--	--	8.76
Total from full stop to full load		**9**	**805.68**	**28.02**	**775.32**	**74.22**	**231.39**
Average emission rates (lbs/hour)			89.52	3.11	86.15	8.25	25.71

1 This refers to the 4-cell cooling towers (2) that are associated with the boiler units.
2 The turbine is assumed to be at full load with the ambient air at 30 °F and the duct burners off.
3 This refers to the 10-cell cooling towers (2) associated with the four combustion turbines.
4 The emission rate for these cooling towers is assumed the same for startup and full load.
5 Unit 1 of the 10-cell cooling tower set will operate 3 hours longer due to the startup sequence, which calls for the unit 4 turbines to begin startup after unit 3 turbines have completed their startup.

Cold startups usually occur after extended periods of shutdown, typically 7 days or more. The cold startup sequence assumes that the boilers are at full load and are supplying steam to the HRSG and steam turbines of CTG Units 3 and 4. MVPC has requested that they assume 36 hours of cold startups per year per turbine for the MVPP facility. AIR QUALITY Table 14 shows the estimated cold start emissions for the MVPP facility. Staff includes start up emissions from the existing boilers (units 1 & 2) and estimates their startup duration at 6 hours total. However, staff also includes emissions from the boilers units while they are at full load. Since the boilers and turbines will operate somewhat independently, the worst case 1-hour and worst case daily emissions will occur while the boilers are at full load and the turbines are in startup mode. The turbines unit 3 will be started first, followed by the turbines in unit 4 (for a total startup duration of 6 hours).

AIR QUALITY Table 14
Cold Startup Emission Estimate
(pounds per event)

Equipment	Operation	Duration (hours)	NOx	SOx	CO	VOC	PM10
Boiler Unit 1	Full Load	6	195.84	4.08	12.24	4.08	1.20
Boiler Unit 2	Full Load	6	195.84	4.08	12.24	4.08	1.20
4-Cell Tower[1] Unit 1	Full Load	6	--	--	--	--	4.62
4-Cell Tower[1] Unit 2	Full Load	6	--	--	--	--	4.62
Unit 3 Turbine 1	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 2	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 1	Full Load[2]	3	49.77	3.96	72.60	9.72	33.00
Unit 3 Turbine 2	Full Load[2]	3	49.77	3.96	72.60	9.72	33.00
Unit 4 Turbine 1	Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 4 Turbine 2	Startup	3	60.00	2.58	150.00	10.41	31.14
10-Cell Tower[3] Unit 1	Full Load[4]	6[5]	--	--	--	--	17.52
10-Cell Tower[3] Unit 2	Full Load[4]	3	--	--	--	--	8.76
Total from full stop to full load		**6**	**731.22**	**26.40**	**769.68**	**69.24**	**228.48**
Average emission rates (lbs/hour)			121.87	4.40	128.28	11.54	38.08

1 This refers to the 4-cell cooling towers (2) that are associated with the boiler units.
2 The turbine is assumed to be at full load with the ambient air at 30 °F and the duct burners off.
3 This refers to the 10-cell cooling towers (2) associated with the four combustion turbines.
4 The emission rate for these cooling towers is assumed the same for startup and full load.
5 Unit 1 of the 10-cell cooling tower set will operate 3 hour longer due to the startup sequence, which calls for the unit 4 turbines to begin startup after unit 3 turbines have completed startup.

Warm startups occur generally after a shorter shutdown duration than those for cold startups, from 2 to 7 days. MVPC will still likely find it necessary to use some steam from the boilers to preheat the HRSG and steam turbines for CTG Units 3 & 4. Staff estimates the startup period to be approximately 2 hours for each turbine for a warm startup. MVPC requests that they have 96 hours of warm startups per year per turbine. AIR QUALITY Table 15 shows the estimated emissions for a warm startup at the MVPP. The turbines unit 3 will be started first, followed by the turbines in unit 4 (for a total startup duration of four hours).

AIR QUALITY Table 15
Warm Startup Emission Estimate
(pounds per event)

Equipment	Operation	Duration (hours)	Nox	SOx	CO	VOC	PM10
Boiler Unit 1	Full Load	4	130.56	2.72	8.16	2.72	0.80
Boiler Unit 2	Full Load	4	130.56	2.72	8.16	2.72	0.80
4-Cell Tower[1] Unit 1	Full Load	4	0.00	0.00	0.00	0.00	3.08
4-Cell Tower[1] Unit 2	Full Load	4	0.00	0.00	0.00	0.00	3.08
Unit 3 Turbine 1	Startup	2	40.00	1.72	125.00	6.94	20.76
Unit 3 Turbine 2	Startup	2	40.00	1.72	125.00	6.94	20.76
Unit 3 Turbine 1	Full Load[2]	2	33.18	2.64	48.40	6.48	22.00
Unit 3 Turbine 2	Full Load[2]	2	33.18	2.64	48.40	6.48	22.00
Unit 4 Turbine 1	Startup	2	40.00	1.72	125.00	6.94	20.76
Unit 4 Turbine 2	Startup	2	40.00	1.72	125.00	6.94	20.76
10-Cell Tower[3] Unit 1	Full Load[4]	4[5]	0.00	0.00	0.00	0.00	11.68
10-Cell Tower[3] Unit 2	Full Load[4]	2	0.00	0.00	0.00	0.00	5.84
Total from full stop to full load		**4**	**487.48**	**17.60**	**613.12**	**46.16**	**152.32**
Average emission rates (lbs/hour)			81.25	2.93	102.19	7.69	25.39

1 This refers to the 4-cell cooling towers (2) that are associated with the boiler units.
2 The turbine is assumed to be at full load with the ambient air at 30 °F and the duct burners off.
3 This refers to the 10-cell cooling towers (2) associated with the four combustion turbines.
4 The emission rate for these cooling towers is assumed the same for startup and full load.
5 Unit 1 of the 10-cell cooling tower set will operate two hour longer due to the startup sequence, which calls for the unit 4 turbines to begin startup after unit 3 turbines have completed startup.

Hot startups generally occur following a trip off line or non-critical emergency shutdown, usually lasting only a few hours. The HRSGs and steam turbines are still warm, so there is no reason to use steam from the boilers to preheat them. Hot startups typically take approximately one hour to complete. MVPC is requesting 233 hours per year per turbine of hot startups. AIR QUALITY Table 16 shows the estimated emissions for a hot startup for the MVPP. The turbines unit 3 will be started first, followed by the turbines in unit 4 (for a total startup duration of 2 hours).

AIR QUALITY Table 16
Hot Startup Emission Estimate
(pounds per event)

Equipment	**Operation**	**Duration (hours)**	**Nox**	**SOx**	**CO**	**VOC**	**PM10**
Boiler Unit 1	Full Load	2	65.28	1.36	4.08	1.36	0.40
Boiler Unit 2	Full Load	2	65.28	1.36	4.08	1.36	0.40
4-Cell Tower[1] Unit 1	Full Load	2	--	--	--	--	1.54
4-Cell Tower[1] Unit 2	Full Load	2	--	--	--	--	1.54
Unit 3 Turbine 1	Startup	1	20.00	0.86	100.00	3.47	10.38
Unit 3 Turbine 2	Startup	1	20.00	0.86	100.00	3.47	10.38
Unit 3 Turbine 1	Full Load[2]	1	16.59	1.32	24.20	3.24	11.00
Unit 3 Turbine 2	Full Load[2]	1	16.59	1.32	24.20	3.24	11.00
Unit 4 Turbine 1	Startup	1	20.00	0.86	100.00	3.47	10.38
Unit 4 Turbine 2	Startup	1	20.00	0.86	100.00	3.47	10.38
10-Cell Tower[3] Unit 1	Full Load[4]	2[5]	--	--	--	--	5.84
10-Cell Tower[3] Unit 2	Full Load[4]	1	--	--	--	--	2.92
Total from full stop to full load		**2**	**243.74**	**8.80**	**456.56**	**23.08**	**76.16**
Average emission rates (lbs/hour)			121.87	4.40	228.28	11.54	38.08

1 This refers to the 4-cell cooling towers (2) that are associated with the boiler units.
2 The turbine is assumed to be at full load with the ambient air at 30 ^{o}F and the duct burners off.
3 This refers to the 10-cell cooling towers (2) associated with the four combustion turbines.
4 The emission rate for these cooling towers is assumed the same for startup and full load.
5 Unit 1 of the 10-cell cooling tower set will operate one hour longer due to the startup sequence, which calls for the unit 4 turbines to begin startup one hour after unit 3 turbines began startup.

OPERATING EMISSIONS

Operating emissions for the MVPP include emission from the combustion turbines, the gas-fired HRSGs (duct firing) and the existing boilers. Emissions from the combustion turbine are susceptible to the ambient temperature. Generally speaking, the colder the ambient temperature is, the denser it is. Denser air results in a slightly higher power output and a higher volume throughput, which tends to result in higher emissions. MVPC investigated emission rates at several different ambient temperatures, with and without duct firing. They found that the highest emissions occur while the combustion turbine is at full load, the ambient temperature is 30 ^{o}F and the duct firing is on. For normal operations, the boilers and all four cooling towers are assumed to be at full load because that scenario is their highest emission state.

MAXIMUM EXPECTED EMISSIONS

The maximum expected emissions for the MVPP are calculated on a hourly, daily and annual basis. AIR QUALITY Table 17 shows the hourly emissions and assume that the boilers are at full load and the combustion turbines are in startup. The HRSG ducts are not fired during startup. AIR QUALITY: Table 18 shows the maximum daily emissions and assumes the existing boilers operating at full load and the new turbines starting up and then operating at full load for the balance of the day. The daily maximum emissions include one hour of operation from the emergency IC engine.

AIR QUALITY Table 17
Project Maximum Hourly Emissions
(lbs/hr)

Equipment : Operation	NOx	SO2	CO	VOC	PM10
Boiler Unit 1: Full Load	32.64	0.68	2.04	0.68	0.20
Boiler Unit 2: Full Load	32.64	0.68	2.04	0.68	0.20
Boiler Cooling Tower 1: Full Load	--	--	--	--	0.77
Boiler Cooling Tower 2: Full Load	--	--	--	--	0.77
CTG Unit 3: Turbine 1 Full Load w/Duct	17.77	1.42	25.91	3.47	11.00
CTG Unit 3: Turbine 2 Full Load w/Duct	17.77	1.42	25.91	3.47	11.00
CTG Unit 4: Turbine 1 Cold Startup	20.00	0.86	50.00	3.47	10.38
CTG Unit 4: Turbine 2 Cold Startup	20.00	0.86	50.00	3.47	10.38
CTG Cooling Tower 1: Full Load	--	--	--	--	2.92
CTG Cooling Tower 2: Full Load	--	--	--	--	2.92
TOTAL	**140.82**	**5.92**	**155.90**	**15.24**	**50.54**

AIR QUALITY Table 18
Project Daily Emissions
(lbs/day)

Equipment : Operation	Duration	NOx	SO2	CO	VOC	PM10
Boiler Unit 1: Full Load	24	783.36	16.32	48.96	16.32	4.80
Boiler Unit 2: Full Load	24	783.36	16.32	48.96	16.32	4.80
4-Cell Tower 1: Full Load	24	--	--	--	--	18.48
4-Cell Tower 2: Full Load	24	--	--	--	--	18.48
Unit 3 Turbine 1:Cold Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 2: Cold Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 3 Turbine 1:Full Load	21	373.17	29.82	544.11	72.87	231.00
Unit 3 Turbine 2: Full Load	21	373.17	29.82	544.11	72.87	231.00
Unit 4 Turbine 1:Cold Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 4 Turbine 2:Cold Startup	3	60.00	2.58	150.00	10.41	31.14
Unit 4 Turbine 1:Full Load	18	319.86	25.56	466.38	62.46	198.00
Unit 4 Turbine 2:Full Load	18	319.86	25.56	466.38	62.46	198.00
10-Cell Tower 1: Full Load	24	--	--	--	--	70.08
10-Cell Tower 2: Full Load	21	--	--	--	--	61.32
Emergency IC Engine	1	19.80	0.44	1.56	1.56	0.81
Total	**24**	**3,212.58**	**154.16**	**2,720.46**	**346.50**	**1,161.33**

The annual emissions for the MVPP are summarized in the AIR QUALITY Table19. The annual emissions include 200 hours of operation from the emergency IC engine, 200 hours of operation from the firewater pump and 1915 hours of operation from the duct burners. The CTG Units are assumed to operate at full load for 8,395 hour per year with an additional 365 hours in startup mode per turbine. The boiler units are assumed to have 3,700 hours of operation per year with an additional 2,314 hours in startup combined, with the balance of time being down.

AIR QUALITY Table 19
Project Annual Emissions
(tons per year [ton/yr])

Equipment	NOx	SOx	PM10	VOC	CO
Turbines (total for all four)[1]	125.15	22.73	196.97	56.55	192.27
Boiler Unit 1[2]	42.68	0.89	2.67	0.89	0.26
Boiler Unit 2[3]	20.61	0.43	1.29	0.43	0.13
Cooling Towers (total for all four)[4]	0.00	0.00	0.00	0.00	27.07
Emergency Engine[5]	1.98	0.04	0.16	0.16	0.08
Firewater Pump[5]	0.20	0.01	0.05	0.03	0.01
Total	**190.62**	**24.09**	**201.14**	**58.05**	**219.82**

1 Assumes each turbine has a total of 365 hours of startup divided as follows: 233 hours of hot starts, 96 hours of warm starts, 36 hours of cold starts. Also assumes each turbine operates at various ambient temperatures as follows: 20 hours at 102 °F and the dust burners on, 850 hours at 82 °F and the duct burners on, 3605 hours at 59 °F and the duct burners off, 2875 hours at 30 °F and the duct burners off, and 1045 hours at 30 °F with the duct burners on. Finally, assumes no down time for the turbines.
2 Assumes 1495 hours of startup and 2500 hours of full load operation.
3 Assumes 819 hours of startup and 1200 hours of full load operation.
4 Assumes the 10-cell cooling towers at in startup for 365 hours and at full load for 8395 hours. Also assumes that unit 1 of the 4-cell cooling towers is in startup for 1495 hours and at full load for 2500 hours. Also assumes that unit 2 of the 4-cell cooling towers is in startup for 819 hours and at full load for 1200 hours.
5 Assumes 200 hours of full load operation
For more information see Appendix B.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NOx emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia mixes in the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered, out the stacks. These ammonia emissions are known as ammonia slip. MSCC has committed to an ammonia slip no greater than 5 ppm, which is the current lowest ammonia slip level being permitted throughout California. On a daily basis, the ammonia slip of 5 ppm is equivalent to approximately 323 lb./day of ammonia emitted into the atmosphere per turbine.

It should be noted that the ammonia slip of 5 ppm is usually associated with the degradation of the SCR catalyst, usually in a time frame of two years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. Through most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to a mass emissions of approximately 60 to 125 pounds per day per turbine. The implications of these ammonia emissions are discussed later in this analysis.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time frame between completion of construction and the consistent production of electricity for sale on the market. Normal operating emission limits usually do not apply during initial commissioning procedures. The turbines used at the MVPP will go through several layers of test during initial commissioning. During the first set of tests, post-combustion control will not be operational (ie., the SCR and oxidation catalyst). MVPC plans to put two turbines through the initial commission phase at a time. Once the first set of turbines has completed the initial commissioning phase, the second set of turbines will begin.

These tests start with a Full Speed-No Load test. This test runs the turbine at approximately 20% of its maximum heat input rate. Components tested include the ignition system, synchronization with the electric generator and the turbine overspeed safety system. This test is expected to last approximately 5 days.

Part Load testing runs the turbines to approximately 60% of the maximum heat input rating over a 6 day period. During this test the turbine and HRSG will be tuned to minimize emissions and the HRSG steam lines will be checked.

Full Load testing runs the turbines to approximately 100% of their maximum heat input rate and lasts approximately 4 days. This testing entails further tuning of the turbine and HRSG as well as the steam lines.

Full Load — Partial SCR testing runs the turbines at 100% of their maximum heat input rate and operates the SCR ammonia injection grid for the first time. This testing is expected to last approximately 5 days.

Finally, Full Load — Full SCR testing runs the turbines at 100% of their maximum heat input rate and operates the SCR ammonia inject grid at its full capacity. It is during this test that the SCR system will be completely tuned and operating at design levels (ie., NOx control at 2.5 ppm). This test is expected to take approximately 14 days for a pair of turbines.

Total initial commissioning for one set of turbines is expected to require approximately 33 days (ie., 66 days for all four turbines at the MVPP). AIR QUALITY Table 20 shows the expected emissions from the initial commissioning of all four turbines in the MVPP.

AIR QUALITY Table 20
Initial Commissioning Emissions Estimate

	NOx	CO	VOC	SOx	PM10
Maximum Hourly Emissions (lbs/hr)	189	411	7	2	22
Maximum Daily Emissions (lbs/day)	2,265	4,931	83	20	264
Total Initial Commissioning Emissions (lbs)	**69,284**	**223,158**	**4,447**	**1,391**	**14,256**

Source (MVPC 2000ff)

FACILITY CLOSURE

Eventually the MVPP will close, either as a result of the end of its useful life, or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions would cease and thus all impacts associated with those emissions would no longer occur.

The Permit to Operate, issued by the District, is required for operation of the facility and is usually renewed on a five year schedule. However, during those five years, the applicant must still pay permit fees annually. If the applicant chooses to close the facility and not pay the permit fees, then the Permit to Operate would be cancelled. In that event, the project could not restart and operate unless the applicant pays the fees to renew the Permit to Operate.

If MVPC were to decide to dismantle the project, there would likely be fugitive dust emissions associated with this dismantling effort. The Facility Closure Plan to be submitted to the Energy Commission Compliance Project Manager should include the specific details regarding how MSCC plans to demonstrate compliance with the District Rules regarding fugitive dust emission limitations.

PROJECT INCREMENTAL IMPACTS

MODELING APPROACH

MVPC performed an air dispersion modeling analysis to evaluate the project s potential impacts on the existing ambient air pollutant levels, both during construction and operation. An air dispersion modeling analysis usually starts with a conservative screening level analysis. Screening models use very conservative assumptions, such as the meteorological conditions, which may or may not actually occur in the area. The impacts calculated by screening models, therefore, can be double or more than the actual or expected impacts. If the screening level impacts are significant, refined modeling analysis is performed. A major difference in the refined modeling is that hour-by-hour meteorological data collected in the vicinity of the project site is used. The Industrial Source Complex Short-Term model, Version 3, known as the ISCST3 model, was used for the refined modeling.

CONSTRUCTION IMPACTS

MVPC performed air dispersion modeling analyses of the potential construction impacts at the project site. The analyses included fugitive dust generated from the construction activity and combustion emissions from the equipment. The emissions used in the analysis were the highest emissions of a particular pollutant during a one month period, converted to a gram per second emission rate for the model. Most of the highest emissions occurred during the 2nd and 7th month of the 20-month construction period.

The results of this modeling effort are shown in AIR QUALITY Table 21. They show that the construction activities would cause a violation of the state 1-hour average NO2 standard and further exacerbate existing violations of the state 24-hour and annual average PM10 standards. In reviewing the modeling output files, the project s construction impacts are not occasional or isolated events, but are over an area within a few hundred meters of the project site.

AIR QUALITY Table 21
Maximum Construction Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)[1]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2[2]	**1-hour**[3]	516	263.2	779.2	470	**166**
	Annual[4]	24	67.54	91.54	100	92
CO[2]	1-hour	1520	5750	7270	23,000	32
	8-hour	836	4444	5280	10,000	53
SO2[2]	1-hour	35	52.4	87.4	655	13
	24-hour	6	28.9	34.9	130	27
	Annual	1	4.8	5.8	80	7
PM10[5]	**24-hour**	62	148	210	50	**420**
	Annual	24	50.6	74.6	30	**249**

1 See AIR QUALITY Table 5.
2 Based on daily emission during month 7.
3 Employs ozone limiting method.
4 Employs ARM method, default district ratio of 0.71.
5 Based on daily emissions during month 2

Source: Response to data request # 15

Since the general public live and work in the vicinity of the project site, the construction of the MVPP may result in unavoidable short-term impacts that may expose the general public to adverse air quality conditions. Thus, staff believes that the impact from the construction of the project could have a significant and unavoidable impact on the NO2 and PM10 ambient air quality standards, and should be avoided or mitigated, to the extent feasible.

PROJECT OPERATION IMPACTS

The air quality impacts of project operation are shown in the following sections for fumigation meteorological conditions, and during the facility start-up (assuming 50% load) and steady-state operations.

FUMIGATION IMPACTS

During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air will also be vertically mixed, bringing some of those emissions down to ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning air pollution event, called fumigation, usually lasts approximately 30 to 90 minutes.

The applicant used the SCREEN3 model, which is an EPA approved model, for the calculation of fumigation impacts. AIR QUALITY Table 22 shows the modeled fumigation results and impacts on the 1-hour NO2, CO and SO2 standards. Since fumigation impacts will not typically occur much beyond a 1-hour period, only impacts on these 1-hour standards were addressed. The results of the modeling analysis show that fumigation impacts at either partial load (50 percent) or full load will not violate the NO2, CO or SO2 1-hour standards.

AIR QUALITY Table 22
Facility Fumigation Modeling Maximum 1-Hour Impacts

Pollutant	Impact[1] ($\mu g/m^3$)	Background[2] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	6.30	263.2	269.5	470	57
CO	9.30	5750	5759.3	23,000	25
SO2	0.50	52.4	52.9	655	8

1 Impacts include emissions from all four turbines
2 See AIR QUALITY Table 5

OPERATIONAL MODELING ANALYSIS

The MVPC provided staff with a modeling analysis, using the ISCST3 model to quantify the potential impacts of the project for both turbines, during normal steady state operation and during start-up conditions. This modeling analysis consisted of a screening level and a refined level analysis. The screening level analysis tested 10 basic operating conditions, which combined various load levels and duct burner operations with several ambient air temperatures. The refined modeling was developed from these screening level runs. The screening level runs showed that the highest impacts occur for short-term averaging periods (24 hours or less) when the boilers (units 1 and 2) and the turbines unit 3 are at full load, while the turbines in unit 4 are in cold start, with the emergency generator operating. The annual impacts (PM10) include the combustion turbines, the boilers, the emergency engine, the firewater pump and the cooling towers in both startup and full load operation. These impacts are shown in AIR QUALITY Table 23.

The project s PM10 impacts could contribute to existing violations of the state 24-hour and annual average PM10 standards. Because of the conservatism of the air dispersion model itself, staff believes that the actual impacts from the project would be somewhat less than the projected modeled impacts shown in AIR QUALITY Table 23.

AIR QUALITY Table 23
Facility Modeling Maximum Impacts

Pollutant	See AIR QUALITY Table #	Averaging Time	Impact ($\mu g/m^3$)	Back-Ground[1] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	17	1-hour	74.0	263.2	337.2	470	72
	19	Annual	0.61	67.54	68.15	100	68
CO	17	1-hour	34.1	5750	5784.1	23,000	25
	17	8-hour	11.5	4444	4455.5	10,000	45
SO2	17	1-hour	2.50	52.4	54.9	655	8
	18	24-hour	0.29	28.9	29.19	130	22
	19	Annual	0.08	4.8	4.88	80	6
PM10	18	**24-hour**	10.10	148	158.1	50	**316**
	19	**Annual**	2.01	50.6	52.61	30	**175**

Note: The applicant has recently changed the exhaust stack of the emergency IC engine and will be required to resubmit new modeling to reflect this change.

1 See AIR QUALITY Table 5

The meteorological data used in the ISCST3 model was a single year from one station. This is atypical for an air dispersion modeling analysis . Typically, the applicant uses 5 years of the most recent meteorological data available. However, in this case the District requires the use of specific meteorological data files that they have examined and corrected for modeling purposes. Generally the District followed the EPA guidelines for correcting errors or missing data in the meteorological data file. This meteorological data was taken from the Redlands monitoring station in 1981 (19 years old). Staff was initially concerned that since this is a single year, the meteorological data might result in low impacts for the modeling effort. However, the CAPCOA Risk Assessment Guidelines for Dry Cleaners (CAPCOA 2000) used this same meteorological data as well as other meteorological data from California and the rest of the United States. The modeling results of the Risk Assessment Guidelines show that the Redlands 1981 meteorological data produce the highest impacts of any other meteorological data using the same type of emission sources. Therefore, staff believes that it is reasonable to base the ISCST3 modeling solely on the Redlands 1981 meteorological data.

SECONDARY POLLUTANT IMPACTS

The project s gaseous emissions of NOx, SO2, VOC and ammonia can contribute to the formation of secondary pollutants, ozone and PM10. There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the MVPP do have the potential (if left unmitigated) to contribute to higher ozone levels in the region.

Secondary PM10 formation, as discussed earlier is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency (EPA or CARB) recommended models or procedures for estimating nitrate or sulfate formation.

Nevertheless, studies during the past two decades have provided data on the oxidation rates of SO2 and NOx. The data from these studies can be used to approximate the conversion of SO2 and NOx to particulate. This can be done by using an aggregate conversion factor (typically about 0.01 to 1 percent per hour) with Gaussian dispersion models such as ISCST3. The model is run with and without chemical conversion (decay factor) and the difference corresponds to the amount of SO2 and NO2 that is converted to particulate. This approach is an over simplification of a complex process; nevertheless, given the stringency of the PM10 standards, and the need to address interpollutant conversion rates in setting offset ratios, for interpollutant trading, staff believes this issue needs to be addressed.

Alternatively, ambient background information exists in the area near the project site that may allow an estimate of the predicted ammonium nitrate formation. The information was measured by the District in a 1995 dairy impact study that was intended to estimate the impacts of dairy farming (a significant source of ammonia) on ambient secondary PM10 formation. The results would have to be restricted to an annual average as the nitrate formation reaction is very dependent on ambient conditions. ~~Staff intends to make these calculations available at a later date (see Appendix A for more information).~~ **Staff has investigated the basic data needed for this analysis and found that even with the 1995 dairy study information, there is insufficient information to attempt this analysis.**

CUMULATIVE IMPACTS

To evaluate reasonably foreseeable future projects as part of a cumulative impacts analysis, staff needs specific and timely information. The time in which a probable future project is well enough defined to have the information necessary to perform a modeling analysis is usually when the project applicant has submitted an application to the District for a permit. Air dispersion modeling required by the District would necessitate that the applicant develop the necessary modeling input parameters to perform a modeling analysis. Therefore, we evaluate those probable future projects in our cumulative impacts analysis that are currently under construction, or are currently under District review. Projects located up to six miles from the proposed facility site usually need to be included in the analysis. Historic and current emissions sources are represented by adding the modeled expected future project emission impacts to the measured background ambient air quality conditions. It is staff s opinion that this method satisfies the cumulative impacts requirement of CEQA.

The applicant has submitted a cumulative impacts analysis that, in staffs opinion satisfies the requirements of CEQA (MVPC 2000pp). This analysis is a revision of an earlier analysis that staff found to be incomplete. The original analysis found no new emission sources within 6 miles of the MVPP that were greater than 15 tons per year. The revised analysis identified 33 new sources from a request through the District, most of which were less than 10 lbs a day and limited to 200 hours of operation a year (i.e. Emergency standby IC engines). There were also flares from local landfills, small boilers and several large aggregations of small sources. Modeling parameters were not readily available for the applicant to use, therefore the applicant substituted stack parameters that had been recently used for similar sources. In staff s opinion these stack parameters are conservative in nature and represent an over estimate of the likely cumulative impacts.

The applicant used the same ISCST3 model and meteorological data file as they did in the refined modeling analysis above. The results are shown in AIR QUALITY Table 23.1. As is indicated by AIR QUALITY Table 23.1, the total cumulative impact from all sources shows a 1-hour NO2 impact and both annual and 24-hour PM10 impacts. The PM10 exceedances were expected because the ambient air quality already exceeds the standards. However, the NO2 exceedance indicates that if these emission sources are left unmitigated, they may have the potential to cause a violation of the 1-hour NO2 ambient air quality standard. The MVPP is likely to be the only source of those that were modeled to be involved in RECLAIM and thus mitigated. The rest of the sources are not likely to be involved in RECALIM because they either are small or are specifically exempted (i.e., emergency IC engines). Staff must note three important issues, first the contribution from the MVPP to the highest cumulative impact is very small. Second, it is very unlikely that if emergency IC engines are operating that the MVPP is also operating. Lastly, it should a very rare event that emergency IC engines are needed, especially if the MVPP is operational. Therefore, it is staff s opinion that the contribution from MVPP is small enough and the circumstances leading to these events are unlikely enough to conclude that there will be no significant cumulative impact from the addition of the MVPP as long as the project emissions are mitigated as proposed (see Mitigation Section).

AIR QUALITY Table 23.1
Mountainview Power Project Cumulative Impacts Analysis

Pollutant / Averaging Period	Maximum Impact from MVPP	MVPP contributio n at point of maximum cumulative impact	33 new sources contribution at point of maximum cumulative impact	Total maximum cumulativ e impact	Back-ground	Total Impact	Ambient Air Quality Standard	Percent of Standard
NO2								
Annual	0.61	0.01	14.58	14.59	67.54	82.13	100	82
1 hour	74.00	0.00	209.90	209.90	263.2	473.1	470	**101**
CO								
8 hour	11.50	0.00	535.13	535.13	4,444	4,979	10,000	50
1 hour	34.10	1.07	69.23	70.30	5,750	5820	40,000	15
SO2								
Annual	0.08	0.00	1.23	1.23	4.8	6.03	80	8
24 hour	0.29	0.00	3.51	3.51	28.9	32.41	109	30
1 hour	2.50	0.00	14.37	14.37	52.7	67.07	650	10
PM10								
Annual[1]	2.01	0.01	18.46	18.47	57.3	75.77	50	**152**
Annual[2]	2.01	0.01	18.46	18.47	50.6	69.07	30	**230**
24 hour	10.10	0.00	54.82	54.82	148	202.8	150	**135**

1 arithmetic mean
2 geometric mean

VISIBILITY IMPACTS

A visibility analysis of the project s gaseous emissions is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis addresses the contributions of gaseous emissions (primarily NOx) and particulate (PM10) emissions to visibility impairment on the nearest Class 1 PSD areas, which are national parks and national wildlife refuges. The nearest Class 1 areas to the MVPP site are the Aqua Tibia Wilderness area, the Cucamonga Wilderness area, the Joshua Tree National Park, The San Gabriel Wilderness Area, the San Gorgonia Wilderness area and the San Jacinto Wilderness area. MVPC used the EPA approved model ISCST3 to assess the project s visibility impacts. The results from the VISCREEN modeling analysis indicated that the project s visibility impacts would be below the significance criteria for contrast and perception. Therefore the project s visibility impacts on these Class 1 areas are considered insignificant.

MITIGATION

APPLICANT S PROPOSED MITIGATION

CONSTRUCTION MITIGATION

MVPC proposes to implement the following measures to reduce emissions during construction activities. The emission estimates from MVPC that follow this section take these control measures into consideration.

To control exhaust emissions from heavy diesel construction equipment

- Limit engine idle time and shutdown equipment when not in use.
- Perform regular preventative maintenance to reduce engine problems.
- Use CARB Low-Sulfur fuel for all heavy construction equipment.
- Ensure that all heavy construction equipment complies with EPA 1996 Diesel standards.

To control fugitive dust emissions

- Use water application or chemical dust suppressant on unpaved travel surfaces and parking areas.
- Use vacuum or water flushing on paved travel surfaces and parking areas.
- Require all trucks hauling loose material to either cover or maintain a minimum of two feet of freeboard.
- Limit traffic speed on unpaved roads to 25 mph.
- Install erosion control measures.
- Re-plant disturbed areas as soon as possible.
- Use gravel pads and wheel washers as needed.
- Use wind breaks and chemical dust suppressant or water application to control wind erosion from disturbed areas.

OPERATIONS MITIGATION

The MVPP s air pollutant emissions impacts will be reduced by using emission control equipment on the project and by providing emission offsets. To reduce NOx emissions, MVPC proposes to use dry-low NOx combustors in the CTGs and a Selective Catalytic Reduction system with an ammonia injection grid.

To reduce CO and VOC emissions, MSCC proposes to use a combination of good combustion and maintenance practices, along with an oxidizing catalyst located in the HRSG. PM10 emissions will be limited by the use of a clean burning fuel (natural gas) and the efficient combustion process of the CTGs. The use of natural gas as the only fuel will limit SO2 emissions.

COMBUSTION TURBINE

Dry Low-NOx Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NOx formed during combustion. Because of the expense and efficiency losses due to steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NOx, CTG manufacturers are presently choosing to limit NOx formation through the use of dry low-NOx technologies. The GE version of the dry low-NOx combustor is a four-stage ignition system. Initially the fuel/air mixture is ignited in two independent combustors (0% to 35% load). Then the startup sequence moves to a lean-lean operation (35% to 70% load) where the center burner is engaged as well. Then second stage burning is begun and all the fuel is directed to the center burner. The second stage burning is a transient event while proceeding to the premixed phase. Premixed operation (70% and 100% load) has fuel being pumped to all burners, but ignition only in the center burner.

In this process, firing temperatures remain somewhat low, thus minimizing NOx formation, while thermal efficiencies remain high. At steady state CTG loads greater than 40 percent load, NOx concentrations entering the HRSG are 25 ppm corrected to 15 percent O2. CO concentrations are more variable, with concentrations greater than 100 ppm at 50 percent load, dropping to 5 ppm at 100 percent load.

FLUE GAS CONTROLS

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSGs. MVPC is proposing two catalyst systems, a selective catalytic reduction system to reduce NOx, and an oxidizing system to reduce CO.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction refers to a process that chemically reduces NOx by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NOx rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950 to 1100^{o}F.

Catalysts generally operate between 600 to 750^{o}F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600^{o}F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800^oF, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770^oF (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

MVPC proposes to use a combination of the dry low-NO_x combustors and SCR system to produce a NO_x concentration exiting the HRSG stack of 2.5 ppm, corrected to 15 percent excess oxygen averaged over a 1-hour period.

Oxidizing Catalyst

To reduce the turbine carbon monoxide (CO) emissions, MVPC proposes to install an oxidizing catalyst, which is similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a noble metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO2). The CO catalyst is proposed to limit the CO concentrations exiting the HRSG stack to 6 ppm, corrected to 15 percent excess oxygen and averaged over 1-hour.

COOLING TOWER

Cooling tower drift consists of small water droplets, which contain particulate matter that originate from the total dissolved solids in the circulating water. To limit these particulate emissions, drift eliminators are installed in the cooling tower to capture these water droplets. MVPC intends to use drift eliminators on the cooling tower, with a design efficiency of 0.0006 percent. This is a very high level of efficiency for cooling tower drift eliminators. Similar cooling tower designs have been used successfully by a number of other projects licensed by the Energy Commission in recent years.

EMISSION OFFSETS

The MVPC has provided a significant amount of emission reduction credits (ERCs) and RECLAIM trading credits (RTCs) to offset the project impacts. ERCs were provided for CO, VOC, SOX and PM10 emissions, while RTCs were provided for NOx emissions. There were insufficient PM10 ERCs to fully offset the MVPP PM10 emissions, therefore MVPC proposed (with the District) to trade SOx ERCs for PM10 emissions at a 2:1 ratio (i.e., 2 pounds of SOx for each pound of PM10). AIR QUALITY Table 24 through 27 shows the ERC certificate number, Company, city of origin and the quantity of pollutant purchased for CO, SOx, VOC and PM10. The quantity purchased is in terms of pounds per day via District banking rules. AIR QUALITY Table 27 shows that one purchase of a PM10 ERC is still pending, the District has indicated that there will likely be no opposition to this purchase on their part but that they are still reviewing it.

AIR QUALITY Table 24
Carbon Monoxide Emission Reduction Credits Procured for the Mountainview Power Project Emission Offsets

Certificate Number	Company	City	Amount (lbs/day)
AQ001463	Alumax Mill Products Inc	Riverside	56
AQ001404	Central Plants Inc	Los Angeles	13
AQ002080	Central Plants Inc	Santa Fe Springs	671
AQ002370, 2372	Rhodia Inc	Carson	30
AQ000979	GWF Power Systems Co.	Newhall	26
AQ002768, 2815	National Offsets	Vernon	11
AQ001481	Granite Construction Co.	Indio	340
AQ001782	Unocal Corp.	Brea	232
Total Emission Reduction Credits			**1,379**

(MVPC 2000nn)

AIR QUALITY Table 25
Sulfur Dioxide Emission Reduction Credits Procured for the Mountainview Power Project Emission Offsets

Certificate Number	Company	City	Amount (lbs/day)
AQ002238	Signal Hill Holding Corp.	Carson	47
AQ000349	GAF Building Materials	Irwindale	114
AQ003046	GAF Building Materials	Irwindale	48
AQ001121	California Steel Industries, Inc	Fontana	50
AQ000563	Miller Brewing	Irwindale	378
AQ000542	California Amforge	Azusa	17
AQ001377	Alcoa	Vernon	88
AQ000333	Technicolor Inc	North Hollywood	4
AQ000668	Hughes Aircraft Company	El Segundo	9
Total Emission Reduction Credits			**755**

(MVPC 2000nn)

AIR QUALITY Table 26
Volatile Organic Compounds Emission Reduction Credits Procured for the Mountainview Power Project Emission Offsets

Certificate Number	Company	City	Amount (lbs/day)
AQ002700	Crown Beverage Packaging Inc	Van Nuys	121
AQ002705	Alumax Mill Products Inc	Riverside	201
AQ001405	Central Plants Inc	Los Angeles	13
AQ001447	Central Plants Inc	Santa Fe Springs	207
Total Emission Reduction Credits			**542**

(MVPC 2000nn)

AIR QUALITY Table 27
PM10 Emission Reduction Credits Procured for the Mountainview Power Project Emission Offsets

Certificate Number	Company	City	Amount (lbs/day)
AQ000765	March AFB	South Gate	10
AQ002594	Internat l Light Metals/Lockheed	Los Angeles	262
AQ002627	Equilon Enterprises	Carson	100
AQ001545	Owens Brockway Glass	Pomona	60
AQ002523	Alumax	Riverside	96
AQ002371	Rhodia Inc	South Gate	3
AQ000545	Southern California Gas Co	Monerey Park	6
AQ002709	Equilon Enterprises	Carson	165
AQ000669	Hughes Aircraft	El Sugundo	25
AQ000011	Firma Inc	South Gate	12
AQ001909	Kiewit-Granite	Hemet	1
AQ002097	Kiewit-Granite	Hemet	26
AQ001910	Kiewit-Granite	Hemet	5
AQ002054, 2256	Kiewit-Granite	Hemet	32
AQ002506	NI Industries	Vernon	4
AQ000376	GE-Energy and Env. Research	Santa Anna	7
AQ002828	National Offset		3
AQ000615	Deluxe Laboratories Inc	Hollywood	11
PENDING	Atkinson, Washington, Zachry	Winchester	105
AQ000350	GAF Building Products	Irwindale	4
AQ000149	Rhodia Inc	Los Angeles	1
AQ000232	Benjamin Moore	Commerce	4
Total Emission Reduction Credits			**942**

(MVPC 2000nn)

AIR QUALITY Table 28 shows the RTCs purchased for the MVPP. This table shows the zone and cycle of each RTC. The zone refers generally to the location and allowable effective area for an RTC. In the case of MVPP, they may use either zone 1 or 2. The cycle refers to the time frame within a year that a RTC is effective. Cycle 1 RTCs are effective from January through December, while cycle 2 RTCs are effective from July through December. The District requires that the applicant purchase enough RTCs to offset the project NOx emissions for the first year of operation. For the MVPP this will be the year 2003. To calculate the RTCs offsets in any year the District adds the total cycle 1 and cycle 2 RTCs from the current year, the cycle 2 RTCs of the previous year and the cycle 1 RTCs of the next year. The adequacy of these ERCs and RTCs will be discussed in the ADEQUACY OF PROPOSED MITIGATION section below. An illustration of this calculation methodology is shown as the bolded figures in AIR QUALITY Table 28. The calculation of these RTCs and ERCs will be discussed further in the LORS Compliance section of this analysis.

AIR QUALITY Table 28
Nitrogen Oxides RECLAIM Trading Credits Procured
for the
Mountainview Power Project Emission Offsets
(Pounds/Year)

Year	RTC	RTC	RTC	RTC	RTC	RTC	RTC	Subtotal for Cycle 1	RTC	RTC	RTC	RTC	RTC	RTC	RTC	Subtotal for Cycle 2	Total
Zone	2	1	1	1	1	1	1		1	1 or 2	1	1	2	1	1		
Cycle	1	1	1	1	1	1	1		2	2	2	2	2	2	2		
2000		10000						10000								0	40000
2001					30000			30000	3100	200						3300	88519
2002		25219			30000			55219	3100	1500						**4600**	145115
2003	2000	20000	5000	13646	30000	11350		**81996**	3100	3000	15000	15000	20750	7120	58800	**122770**	**294688**
2004	5326	20000	5000	13646	30000	11350		**85322**	3100	3000	15000	15000	20750	7120	58800	122770	566184
2005	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2006	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2007	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2008	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2009	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2010	5326	20000	5000	13646	30000	11350	150000	235322	3100	3000	15000	15000	20750	7120	58800	122770	716184
2010 +	5326	20000	5000	13646	30000	11350	150000	235322	3100	6592	15000	15000	20750	7120	58800	126362	484454

(MVPC 2000nn)

ADEQUACY OF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

Staff finds that the mitigation proposed of fugitive dust control is reasonable and will mitigate the impacts from fugitive dust to the extent feasible. However, staff finds that there are further mitigation measures possible for the control of combustion emissions from construction equipment. These additional mitigation measures are discussed in the Staff Proposed Mitigation section below.

OPERATIONS MITIGATION

EMISSION CONTROLS

MVPC has proposed, in their opinion, all practical and technically feasible mitigation measures to limit NOx emissions from the combustion turbines to 2.5 ppm over a 1-hour average. In addition, they propose to use an oxidizing catalyst to limit CO emissions to 6 ppm over a 1-hour period, which will also limit VOC emissions to 1.4 ppm over a 1-hour period.

MVPC s use of drift eliminators with an efficiency of 0.0006 percent represent the state-of-the-art of drift eliminator design. To our knowledge, commercially available drift eliminators with even higher efficiency, which could further reduce the cooling tower s PM10 emissions, are not available.

OFFSETS

The emission reduction credits (ERCs) and RECLAIM trading credits (RTCs) identified in AIR QUALITY Tables 24 through 28 are intended to mitigate the MVPP air quality impacts. The amount of ERCs determined necessary for the MVPP (the ERC liability) is based on the daily average of the worst case month. In the case of MVPP this is most likely to be in the August time frame. The directive from the District is to calculate the total expected monthly emissions from the MVPP for August and divide that total by 30 (days per month) to determine the daily average. These calculations will be shown in more detail in the Compliance with LORS section of this analysis. The significant difference between the determination of the ERC liability required by the District and that shown in AIR QUALITY Table 29 is the inclusion of the new boiler emissions (above historic background emissions), the emergency IC engine, the firewater pump and the cooling towers. The Historic boiler emissions, shown in AIR QUALITY Table 29, are based on actual measured emissions from the facility for the RECLAIM program. It is staff s opinion that the applicant should not be held responsible for these emissions and thus they are discounted from the ERC liability calculation (see Net liability column). The MVPC could not procure enough PM10 ERCs to mitigate the MVPP air quality impacts. Therefore, MVPC proposed, with the District, to trade SOx ERCs for MVPP PM10 emissions at a 2:1 ratio.

AIR QUALITY Table 29
Comparison of Expected Annual Emissions to Offsets Provided
(tons/year)

	Annual Liability[1]	Historic Boiler Annual Emissions[2]	Net Liability	RTC or ERC Procured[3]	Remaining Liability	Convert SOx to PM10[4]	Final Liability
NOx	190.62	36.10	154.51	147.34	7.17		7.17
CO	219.82	0.79	219.04	251.67	-32.63		-32.63
VOC	58.05	0.26	57.79	98.92	-41.13		-41.13
SOx	24.09	0.26	23.83	137.79	-113.96		0
PM10	201.14	0.08	201.06	171.92	29.15	56.98	-27.83

1 See AIR QUALITY Table 19
2 Based on emissions reported in RECLAIM from September 1998 to August 1999.
3 Based on summary of current status of RTCs and ERCs, September 21, 2000.
4 Assuming a 2:1 ratio of SOx to PM10.

AIR QUALITY Table 29 shows that the ERCs provided adequately mitigate the MVPP air quality impacts with the exception of NOx. The NOx RTCs fell short of mitigating the MVPP air quality impacts by 7.17 tons per year. Since it is unlikely that the MVPP will cause or contribute to an exceedance of the NO_2 ambient air quality standards (see Incremental Impacts section), ozone and secondary PM10 impacts become are our primary concerns. Since the MVPC provided an excess of VOC ERCs (41.13 tons/year), which can also contribute to ozone and secondary PM10 impacts. Therefore, it is staff s opinion that the excess VOC ERCs should be reasonable expected to mitigate the remaining NOx emission impacts. Furthermore, the NOx annual liability shown in AIR QUALITY Table 29 includes approximately 63 tons/year of NOx emissions from the existing boilers. This was done at the applicant s request for added conservatism. These boilers have their own RTC mitigation, and therefore should not be counted against the applicant. Therefore staff finds that the applicant has secured sufficient RTCs to mitigate the potential NOx emission impacts from the proposed project.

AIR QUALITY Table 30 compares the RTCs and ERCs provided to the expected worse case daily emissions. The significant difference between Table 29 and 30 is the assumption concerning the historic boiler emissions. In the case of annual emissions, the boilers do not run each day. In the worse case daily emissions, the boilers run for the entire 24 hour period, thus relieving a higher percentage of NOx liability than in the annual case. AIR QUALITY Table 30 shows that the CO ERCs fall short of fully offsetting the CO emissions from MVPP by 1,284 lbs/day. This is due to the assumption MVPC used to determine the worse month daily average CO liability as compared to staff assumptions for the worst case daily emissions. MVPC assumed that the MVPP could, on a monthly basis, achieve a 2.0 ppm CO emission rate. Staff assumes that the worst case daily CO emission will be 6.0 ppm. Because CO emissions from MVPP will be monitored by a continuous emission monitoring system (CEM), a 2.0 ppm monthly average and a 6.0 ppm hourly average can both be verified. Additionally, the Incremental Impacts section shows there is very little possibility that MVPP will cause or contribute to an impact on the ambient air quality standards for CO. Therefore, staff finds there to be no compelling reason for MVPC to provide further mitigation for their CO emission impacts.

AIR QUALITY Table 30
Comparison of Expected Daily Emissions to Offsets Provided
(pounds/day)

	Daily Liability[1]	Historic Boiler Daily Emissions[2]	Net Liability	RTC Or ERC Procured[3]	Remaining Liability	Convert SOx to PM10[4]	Final Liability
NOx	3,213	2,646	566	807	-241		-241
CO	2,720	58	2,663	1,379	1,284		1,284
VOC	347	19	327	542	-215		-215
SOx	154	19	135	755	-620		0
PM10	1,161	6	1,156	942	214	310	-96

1 See AIR QUALITY Table 18
2 Based on emission factors consistent with emissions reported in RECLAIM from September 1998 to August 1999 and assuming 24 hours of operation.
3 Based on summary of current status of RTCs and ERCs, September 21, 2000.
4 Assuming a 2:1 ratio of SOx to PM10.

STAFF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

The modeling assessment discussed earlier shows that the combustion sources used for heavy construction have the potential for causing significant air quality impacts. After responding to a staff data request directing MVPC to investigate 11 different mitigation options, MVPC has determined that the following options are reasonable mitigation measures that they will consider further but have not agreed to at this time.

- Timing retardation on older diesel construction equipment that does not use a fuel injection system (referred to as a common rail).
- Employ were possible construction equipment that uses the common rail, high-pressure fuel injection system.
- Ensure that all on-road gasoline powered vehicles are equipped with a catalytic converter.
- Ensure that idle time on all diesel power construction equipment is minimized to less than 5 minutes.

- Employ oxidizing soot filters and oxidation catalysts where applicable.

Staff proposes Conditions of Certification AQ-C1 through AQ-C3 to be considered with these mitigation measures.

OPERATIONS MITIGATION

Neither EPA nor CARB have raised any questions regarding the validity of the ERCs or RTCs provided at this time. Staff, therefore, finds that these ERCs and RTCs are valid to offset the project emission impacts. Staff finds that with the proposed emission controls, ERCs and RTCs provided, there is no further mitigation necessary for the project emission impacts.

COMPLIANCE WITH LORS

FEDERAL

The District has not yet issued a Final Prevention of Significant Deterioration (PSD) permit as part of their Determination of Compliance for the MVPP.

STATE

MVPC will demonstrate that the MVPP will comply with Section 41700 of the California State Health and Safety Code when the District issues the Final Determination of Compliance and the CEC staff s affirmative finding for the project.

LOCAL

Compliance with specific SCAQMD rules and regulations are discussed below. For a more detailed discussion of the compliance of the Mountainview project, please refer to the Determination of Compliance (SCAQMD 2000d).

REGULATION II —PERMITS

RULE 218 — CONTINUOS EMISSION MONITORING

The MVPP will be required to install a CO CEMS to verify emissions of CO meet the hourly and daily emission limits. The CO CEMS will need to comply with the requirements of Rule 218, and the facility will need to submit a CEMS application for District review and approval prior to installing the CEMS.

REGULATION IV —PROHIBITIONS

This regulation sets forth the restrictions for visible emissions, odor nuisance, fugitive dust, various air emissions, fuel contaminants, start-up/shutdown exemptions and breakdown events. Please note that San Bernardino County Rule 53 and 53A have not been superseded by District rules and may apply to this project.

RULE 401 — VISIBLE EMISSIONS

Visible emissions are not expected under normal operating conditions of the turbines.

RULE 402 — NUISANCE

Nuisance problems are not expected under normal operating conditions of the turbines.

RULE 403 — FUGITIVE DUST

The applicant will submit a fugitive dust plan to both the District and the Commission.

RULE 407 — LIQUID AND GASEOUS AIR CONTAMINANTS

This rule limits the CO emissions to 2000 ppm max, and the sulfur content of the exhaust to 500 ppm for equipment not subject to the emission concentration limits of 431.1. Since the turbines are subject to the limits of Rule 431.1, only the 2000 ppm limit of this rule applies. It is expected that the equipment will be able to meet the CO limit with the use of an oxidation catalyst. Compliance will be verified through CEMS data.

RULE 409 — COMBUSTION CONTAMINANTS

Limits PM emissions to 0.1 gr/scf. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas 60 mmscf/hr

$$\text{Grain loading} = \frac{11 \text{ lbs/hr } (7000 \text{ gr/lb})}{60 \text{ E+06 scf/hr}}$$

$$= 0.00128 \text{ gr/scf}$$

Compliance will be verified through the initial performance test as well as periodic testing as required by Title V.

RULE 431.1 — SULFUR CONTENT OF GASEOUS FUELS

The rule requires that gas fired equipment meet a sulfur content limit of 40 ppm on a 4 hour averaging time. Commercial grade natural gas to be burned in the turbines is expected to meet this limit.

RULE 431.2 — SULFUR CONTENT OF LIQUID FUELS

This rule establishes a sulfur content limit for diesel fuel of 0.05% by weight, as well as, record keeping requirements and test methods. The project owner shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

RULE 475 — ELECTRIC POWER GENERATING EQUIPMENT

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants (combustion contaminants are defined as particulate matter in AQMD Regulation I) of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the Mountainview turbines are estimated at 11 lbs/hr. However, on a concentration basis estimated grain loading is 0.00128 gr/scf (see calculations under Rule 409 discussion). Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as periodic testing required by Title V.

REGULATION IX — STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Regulation IX incorporates provisions of Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR) and is applicable to all new, modified or reconstructed sources of air pollution. Sections of this regulation apply to electric utility steam generators (Subpart Da) and stationary gas turbines (Subpart GG). These subparts establish limits of particulate mater, SO_2 and NO_2 emissions from the facility as well as monitoring and test method requirements. The MVPP is expected to surpass these emission limits with the controls proposed.

REGULATION XIII — NEW SOURCE REVIEW

This regulation sets forth the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. This regulation limits the emissions of non-attainment contaminants and their precursors as well as ozone depleting compounds (ODC) and ammonia by requiring the use of Best Available Control Technologies (BACT). However, this regulation does not apply to NOx or SOx emissions, which are regulated by Regulation XX (RECLAIM). The applicant has complied with all requirements of the Regulation.

REGULATION XVII — PREVENTION OF SIGNIFICANT DETERIORATION

This regulation sets forth the pre-construction requirement for stationary sources to ensure that the air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth. This regulation establishes maximum allowable increases over ambient baseline concentrations for each pollutant. It is likely that the MVPP will trigger PSD for NOx only. The PSD will be issued by the District as part of the Final Determination of Compliance.

REGULATION XX — REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

The Regional Clean Air Incentives Market (RECLAIM) is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications, reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reductions. The RECLAIM program establishes an initial allocation (beginning in 1994) and an ending allocation (to be attained by the year 2003) for each facility within the program (Rule 2002). Each facility then reduces their allocation annually on a straight line from the initial to the ending. The RECLAIM program supercedes other district rules, where there are conflicts. As a result, the RECLAIM program has its own rules for permitting, reporting, monitoring (including CEM), record keeping, variances, breakdowns and the New Source Review program, which incorporates BACT requirements (Rules 2004, 2005, 2006 and 2012). RECLAIM also has its own banking rule, RECLAIM Trading Credits (RTCs), which is established in Rule 2007. The MVPP is exempt from the SOx RECLAIM program (Rule 2011) because it uses natural gas exclusively (per Rule 2001). However, it will be a NOx RECLAIM project and therefore subject to the rules of RECLAIM for NOx emissions. The applicant has complied with all aspects of the RECLAIM Regulation.

REGULATION XXX — TITLE V PERMITS

The Title V federal program is the air pollution control permit system require by the federal Clean Air Act as amended in 1990. Regulation XXX defines the permit application and issuance as well as compliance requirements associated with the program. Any new or modified major source which qualifies as a Title V facility must obtain a Title V permit prior to construction, operation or modification of that source. Regulation XXX also integrates the Title V permit with the RECLAIM program such that a project cannot proceed without the other. The District will issue the Title V permit as part of the Permit to Construct.

REGULATION XXXI — ACID RAIN PERMITS

Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOX, NOx and CO2 emissions from the facility. It is expected that MVPP will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with gas analysis.

LOCAL - SAN BERNARDINO COUNTY

At this time it is unclear what agency will be enforcing these rules, the District or the County.

RULE 53 — SPECIFIC CONTAMINANTS

This rule restricts the emission of sulfur to 0.1% by volume and combustion contaminants to 0.3 grain per cubic foot at 12% CO_2. This rule also restricts the emissions of fluorine to less than that which would cause injury to the property of others. The emission restrictions placed on the applicant will ensure compliance with this rule.

RULE 53A — SPECIFIC CONTAMINANTS

This rule restricts the emission of SO2 to 500 ppm at 12% CO2, combustion contaminants to 0.1 grains per cubic foot at 12% CO2 and several other non-criteria pollutants. The emission restrictions placed on the applicant will ensure compliance with this rule.

CONCLUSIONS AND RECOMMENDATIONS

~~Staff can make no conclusions until after the revised cumulative analysis has been completed and the District has released the preliminary Determination of Compliance (PDOC). Staff expects the MVPC to issue the cumulative analysis at a later date, staff will issue a revised analysis at that time. Once the District has released the PDOC, staff will issue a revised analysis that incorporates the conditions within the PDOC.~~

~~However, to facilitate the process of licensing the MVPP, staff recommends the following construction related conditions of certification (AQ-C1 through 3).~~
The MVPP s emissions of NOx, SO2 and CO will not cause a violation of any NO2, SO2 or CO ambient air quality standards, and therefore, their impacts are not significant. The project s air quality impacts from directly emitted PM10 and of the ozone precursor emissions of NOx and VOC and PM10 precursors of NOx and SO2 could be significant if left unmitigated. MVPP will reduce emissions to the extent feasible and provide emission offsets for their NOx, VOC, SO2 and PM10 emissions, and thus these mitigation measures reduce

the potential for directly emitted PM10, as well as ozone and secondary PM10 formation to a level of insignificance.

The District has submitted a Preliminary Determination of Compliance (SCAQMD 2000d) that concludes that the MVPP will comply with all applicable District rules and regulations and therefore has proposed a set of conditions presented here as Conditions of Certification AQ-1 through AQ-28, AQ-36 through AQ-38, AQ-45 and AQ-46. However, the applicant has proposed that the project include the existing boiler systems associated with this facility. Therefore, the conditions under which the existing boilers operate must, in staff s opinion, be incorporated into the Conditions of Certification. These existing boiler conditions are proposed here as Conditions of Certification AQ-31, AQ-39 through AQ-41 and AQ-47 through AQ-55.

CEC staff recommends the inclusion of three additional Conditions of Certification (AQ-C1, -C2 and AQ-C3) that address the construction related impacts. Staff also recommend additional conditions to ensure compliance with the assumptions made in this analysis. The additional conditions are Conditions of Certification AQ-8, AQ-29, AQ-30, AQ-32 through AQ-35 and AQ-42 through AQ-44.

Staff therefore recommends the certification of the MVPP with the following proposed Conditions of Certification barring any significant impediments for the District to issue a Final Determination of Compliance.

CONDITIONS OF CERTIFICATION

The following two tables correlate the District proposed conditions from the preliminary Determination of Compliance to the staff proposed Conditions of Certification. It is staff s opinion that these tables are necessary due to the complex nature of the District permitting system. The first table, AIR QUALITY Table 31 show the District conditions and requirements in the left most column and the corresponding staff conditions in the right most column. The middle column is a brief description of the intent of each proposed condition. AIR QUALITY Table 32 switched the end columns around so as to provide cross-indexing.

AIR QUALITY Table 31
District ~ Commission Staff
Conditions of Certification

District	Notes	Commission
Section H	This contains the description and identification numbers for each component of the MVPP, with the exception of the proposed cooling towers. Also note that the PDOC is only addressing the four new combustion turbines, not the existing boiler systems.	Preambles within sections of the proposed conditions.
The following conditions concern the gas turbines only.		
1-1	Emission limits for initial commissioning.	AQ-2
12-1	Ammonia injection monitoring.	AQ-3
12-2	SCR temperature monitoring.	AQ-4
28-1	Initial source testing requirement (NOx, CO, SOx, ROG, PM10 and ammonia).	AQ-15
28-2	On going source testing requirement (quarterly for ammonia only).	AQ-16
40-1	Source test requirements in addition to 28-1.	AQ-15, -16 and -17
57-1	Startup requirement, SCR must be hot.	AQ-9
63-1	Monthly emission limits.	AQ-12
67-1	Record keeping requirement during initial commissioning	AQ-1
82-2	CEMS, NOx monitoring and reporting requirements from first fire to CEMS verification.	AQ-6,-7
99-1	Exception for NOx limit (2.5 ppm, hourly) for initial commissioning and startup. Limit on initial commissioning (33 days, 2 turbines at a time). Limit on startup (3 hours, 2 turbines at a time).	AQ-1, -10
99-2	Exception for NOx limit (2.0 ppm, annual) for initial commissioning and startup. Limit on initial commissioning (33 days, 2 turbines at a time). Limit on startup (3 hours, 2 turbines at a time).	AQ-1, -10

AIR QUALITY Table 31
continued

District	Notes	Commission
99-3	Exception for CO limit (6 ppm) for initial commissioning and startup. Limit on initial commissioning (33 days, 2 turbines at a time). Limit on startup (3 hours, 2 turbines at a time).	AQ-1, -10
99-4	Exception for NOx limit (64 lbs/mmscf) for initial commissioning and part load (60% or lower).	AQ-1
99-5	Exception for NOx limit (32 lbs/mmscf) for initial commissioning and part load (60% or lower). Limit on NOx CEMS certification interim reporting period (12 month).	AQ-2
99-6	NOx limit for initial commissioning period.	AQ-1
99-7	NOx emission limits for startup.	AQ-10
179-1	Ammonia monitoring requirement.	AQ-3
179-2	Ammonia monitoring requirement.	AQ-3
195-1	Hourly NOx limit (2.5ppm).	AQ-11
195-2	Hourly CO limit (6 ppm).	AQ-11
195-3	Hourly Ammonia limit (5 ppm).	AQ-11
195-4	Annual NOx limit (2.0 ppm).	AQ-13
327-1	Hourly PM10 limit (11 lbs/hr).	AQ-14
372-1	Annual P10 source testing.	AQ-17
The following conditions concern the diesel emergency generator only.		
F14-1	Sulfur content limit for diesel fuel.	AQ-18
1-1	Annual use limit (200 hours).	AQ-23
12-3	Elapsed timer requirement.	AQ-20
67-2	Record keeping requirements.	AQ-21
162-1	Limit to emergency use only.	AQ-22
177-1	Engine timing retardation setting (4 degrees).	AQ-19
The following conditions concern the diesel fire water pump only.		
F14-1	Sulfur content limit for diesel fuel.	AQ-24
1-1	Annual use limit (200 hours).	AQ-28
12-3	Elapsed timer requirement.	AQ-26
67-1	Record keeping requirements	AQ-27
177-1	Engine timing retardation setting (4 degrees).	AQ-25
The following conditions concern the ammonia storage tanks only.		
144-1	Venting limitation.	AQ-45
157-1	Pressure relief valve.	AQ-46
The following conditions shall apply to all devices subject to RECLAIM		
296-1	Requires the MVPP to retain adequate RTCs for the gas turbines.	AQ-36
F9-1	Opacity limitation	AQ-37
F18-1	Acid rain allowance	AQ-38

AIR QUALITY Table 32
Commission Staff ~ District
Conditions of Certification

Commission	Notes	District
The following conditions concern the construction of the proposed project only.		
AQ-C1	Engine tuning and fuel requirements.	--
AQ-C2	Soot-filter requirement	--
AQ-C3	Fugitive dust mitigation plan requirement.	--
The following conditions concern the gas turbines only.		
preamble	Equipment description and identification numbers	Section H
AQ-1	Initial commissioning limits and definitions. Staff included a mass emission limit for initial commissioning that was not stated in the PDOC (69,284 lbs).	67-1, 99-1,-2,-3,-4 and -6
AQ-2	Limits for the first 12 months following first fire .	1-1 and 99-5
AQ-3	Ammonia monitoring system requirements.	12-1, 179-1, 179-3
AQ-4	SCR temperature gauge	12-2
AQ-5	CO CEMS requirement	82-1
AQ-6	NOx CEMS requirement	Part of 82-2
AQ-7	NOx reporting requirements	The rest of 82-2
AQ-8	Quarterly Operation Reports, required by Staff to verify compliance of emission limts.	--
AQ-9	SCR operation, staff added language regarding the inclusion of the duct burners along with the gas turbines for this condition.	57-1
AQ-10	Defines startup and shutdown, applies time and emission limits.	99-1, 99-2, 99-3, 99-4 and 99-7.
AQ-11	Gas turbine exhaust short-term emission limits, staff added mass emission limits to the District concentration limits.	Part of 63-1, 195-1, 195-2 and 195-3
AQ-12	Gas turbine exhaust monthly emission limits.	The rest of 63-1.
AQ-13	Gas turbine exhaust annual NOx emission concentration limit. Staff has added a annual NOx mass emission limit.	195-4
AQ-14	Gas turbine exhaust PM10 emission limit.	327-1
AQ-15	Initial source testing requirements, staff added specific language from District 304 (site in District condition).	28-1 and 40-1
AQ-16	Quarterly ammonia source testing requirements.	28-2 and 40-1
AQ-17	Annual PM10 source testing, staff added specific language from District 304.	372-1 and 40-1

AIR QUALITY Table 32
continued

Commission	Notes	District
The following conditions concern the diesel emergency generator only.		
preamble	Equipment description and identification numbers.	Section H
AQ-18	Sulfur limit on fuel oil	F14-1
AQ-19	Engine retardation setting	177-1
AQ-20	Elapsed timer requirement	12-3
AQ-21	Recording requirements	67-2
AQ-22	Emergency IC engine restricted use	162-1
AQ-23	Limit of IC engine use to 200 hours per year.	1-1
The following conditions concern the diesel fire water pump only.		
preamble	Equipment description and identification numbers.	Section H
AQ-24	Sulfur limit on fuel oil	F14-1
AQ-25	Engine retardation setting	177-1
AQ-26	Elapsed timer requirement	12-3
AQ-27	Recording requirements	67-1
AQ-28	Limit of IC engine use to 200 hours per year.	1-1
The following conditions concern the proposed cooling towers (4) only.		
preamble	Equipment description	--
AQ-29	Required to submit drift eliminator designs.	--
AQ-30	Required to submit cooling tower designs.	--
AQ-31	Restricted from using hexavalent chromate in cooling tower.	**Existing PTO** for boiler units, 23-3
AQ-32	Requires that drift eliminators are designed and built to have a drift rate of 0.0006%.	--
AQ-33	PM10 mass emission limits for both 10-cell and 4-cell cooling towers.	--
AQ-34	How the applicant will demonstrate PM10 compliance for the cooling towers.	--
AQ-35	Requires a TSD analysis for the circulating water.	--
The following conditions shall apply to all devices subject to RECLAIM.		
Preamble	Equipment description and identification numbers	Section H
AQ-36	Requires the MVPP to retain adequate RTCs for the gas turbines.	296-1
AQ-37	Opacity limitation.	F5-9
AQ-38	Acid rain allowance.	F18-1

AIR QUALITY Table 32
continued

Commission	Notes	District
The following conditions shall apply to the existing boiler units 1 and 2, as identified in the PTO for the existing Boiler units.		
preamble	Equipment description and identification numbers.	Section D
AQ-39	Sulfur content restriction of natural gas burned and CO emission limit.	**Existing PTO** Section D, emissions and requirements
AQ-40	PM10 emission limit.	
AQ-41	NOx CEMS requirement.	
AQ-42	Quarterly Operational Report to the Commission regarding the boiler units.	--
AQ-43	Combined mass emission limit for both boiler units together.	--
AQ-44	Requires the submission of emission control designs for the boiler units.	--
The following conditions shall apply the proposed ammonia storage tanks.		
preamble	Equipment description and identification numbers	Section H
AQ-45	Venting limitation.	144-1
AQ-46	Pressure relief valve.	157-1
The following conditions apply to the existing gasoline storage tanks, as identified in the PTO for the existing Boiler units.		
Preamble	Equipment description and identification numbers.	Section D
AQ-47	Storage tank and nozzle comply with District Rule 461.	23-1
AQ-48	Project owner shall use phase I vapor recovery system.	109-1
AQ-49	Project owner shall use phase II vapor recovery system.	110-1
AQ-50	Personnel training required.	330-1
The following conditions apply to the existing abrasive blasting equipment, as identified in the PTO for the existing Boiler units.		
Preamble	Equipment description and identification numbers.	Section D
AQ-51	Record keeping requirements.	67-1
AQ-52	Annual inspection requirements.	332-1
AQ-53	Annual inspection reporting requirements.	381-1
AQ-54	Oil-water separators must comply with District Rule 464.	23-2
AQ-55	Record keeping requirements for paints and thinners.	67-2

AQ-C1 The project owner shall require as a condition of its construction contracts that all contractors/subcontractors ensure that all heavy earthmoving equipment, that includes, but is not limited to bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer s specifications. The project owner shall further require as a condition of its construction contracts that this equipment shall employ high pressure fuel injection (common rail) system or engine timing retardation to control the emissions of oxides of nitrogen. **The project owner shall further require as a condition of its construction contracts that all diesel fired construction equipment use CARB Low-Sulfur fuel (<15ppm sulfur by weight). The project owner shall further require as a condition of its construction contracts that all heavy construction equipment complies with EPA 1996 Diesel standards.** The project owner shall further require as a condition of its construction contracts that all heavy construction equipment to the extent practical shall remain running at idle for no more than 5 minutes.

<u>**Verification:**</u> The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor s/subcontractor s heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer s specifications. The project owner shall maintain construction contracts on the site for six months following the start of commercial operation.

AQ-C2 The project owner shall install oxidizing soot filters on all suitable **off-road** construction equipment used either on the power plant construction site or associated linear construction sites. Where the oxidizing soot filter is determined to be unsuitable, the owner shall install and use an oxidation catalyst. **Factors relevant to the suitability analysis shall include, but are not limited to, equipment size and operating time on location.** Suitability is to be determined by an independent California Licensed Mechanical Engineer, **in consultation with the California Air Resources Board (ARB),** who will stamp and submit for approval an initial **suitability report for each major project component; the Wastewater connector line, Natural gas supply line and the Facility sit~~e, respectively~~.** ~~and~~ **The independent California Licensed Mechanical Engineer, in consultation with ARB, shall also submit the Installation Report and** all Suitability Update Reports as necessary containing at a minimum the following:

Initial Suitability Report:

- a list of all fuel burning, construction related equipment used,
- a determination of the suitability of each piece of equipment to firstly work appropriately with an oxidizing soot filter,

- a determination of the suitability of each piece of equipment to secondly work appropriately with an oxidation catalyst,
- ~~if a piece of equipment is determined to be suitable for an oxidizing soot filter, a statement by the independent California Licensed Mechanical Engineer that the oxidizing soot filter has been installed and is functioning properly~~,
- if a piece of equipment is determined to be unsuitable for an oxidizing soot filter, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination,
- ~~if a piece of equipment is determined to be unsuitable for an oxidizing soot filter, but suitable for an oxidation catalyst, a statement by the independent California Licensed Mechanical Engineer that the oxidation filter has been installed and is functioning properly~~ and
- if a piece of equipment is determined to be unsuitable for both an oxidizing soot filter and an oxidizing catalyst, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination.

Installation Report
Following the installation of either the oxidizing soot filter or oxidizing catalyst as prescribed in the Initial Suitability Report, a California Licensed Mechanical Engineer will issue an Installation Report that either confirms that the installed device is functioning properly or that installation was not possible and the cause. The installation report shall include copies of receipts of purchase or lease for the appropriate equipment and receipts of payments for labor if applicable.

Suitability Update Reports
If a piece of construction equipment is subsequently determined to be unsuitable for an oxidizing soot filter or oxidizing catalyst after such installation has occurred, the filter or catalyst may be removed immediately. However notification must be sent to the CPM for approval containing an explanation for the change in suitability within 10 days. Changes in suitability are restricted to three explanations which must be identified in any subsequent suitability report. Changes in suitability may not be based on the use of high-pressure fuel injectors, timing retardation and/or reduced idle time.

1. The filter or catalyst is **excessively** reducing normal availability of the construction equipment due to increased downtime, and/or power output due to increased back pressure ~~by 20% or more~~.
2. The filter or catalyst is causing or reasonably expected to cause significant damage to the construction equipment engine.
3. The filter or catalyst is causing or reasonably expected to cause a significant risk to nearby workers or the public.

<u>Verification:</u> The project owner will submit to the CPM **and ARB** for approval, the Initial Suitability Report stamped by an independent California Licensed Mechanical Engineer, ~~60~~**1530** days prior to breaking ground on the project site. **The project owner will submit to the CPM and ARB for approval, the Installation Report stamped by an independent California Licensed Mechanical Engineer Engineer no later than 10 working day following the use of the identified equipment on site.** The project owner will submit to the CPM **and ARB** for approval, Suitability Update Reports as required, stamped by an independent California Licensed Mechanical Engineer no later than 10 working day following a change in the suitability status of any construction equipment.

AQ-C3 Prior to breaking ground at the project site, the project owner shall prepare a Construction Fugitive Dust Mitigation Plan that will specifically identify fugitive dust mitigation measures that will be employed for the construction of the Mountainview Power Plant and related facilities.

The Construction Fugitive Dust Mitigation Plan shall specifically identify measures to limit fugitive dust emissions from construction of the project site and linear facilities. Measures that should be addressed include the following:

- the identification of the employee parking area(s) and surface of the parking area(s);
- the frequency of watering of unpaved roads and disturbed areas;
- the application of chemical dust suppressants;
- the use of gravel in high traffic areas;
- the use of paved access aprons;
- the use of posted speed limit signs;
- the use of wheel washing areas prior to large trucks leaving the project site;
- the methods that will be used to clean tracked-out mud and dirt from the project site onto public roads; and,
- the use of on-site monitoring devices.

<u>Verification:</u> At least sixty (60) days prior to breaking ground at the project site, the project owner shall provide the CPM with a copy of the Construction Fugitive Dust Mitigation Plan for approval.

The following Conditions of Certification pertain to the following equipment:
1,991 MMBTU/HR Gas Turbine (ID No. D18) (A/N 366147) No. 3-1 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW Electric Generator (ID No. B19) and a Heat Recovery Steam Generator (ID No. B20) with 135 MMBTU/HR Duct Burners (ID No. D21) connected in common with Gas Turbine No. 3-2 to a 214.5 MW steam turbine (ID No. B22). Selective Catalytic Reduction (ID No. C24) (A/N 366151) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B25) and a CO oxidation catalyst (ID No. C23) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S35) (A/N 366146) No 3-1/3-2.

1,991 MMBTU/HR Gas Turbine (ID No. D27) (A/N 366148) No. 3-2 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW Electric Generator (ID No. B28) and a Heat Recovery Steam Generator (ID No. B29) with 135 MMBTU/HR Duct Burners (ID No. D30) connected in common with Gas Turbine No. 3-1 to a 214.5 MW steam turbine (ID No. B31). Selective Catalytic Reduction (ID No. C33) (A/N 366152) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B34) and a CO oxidation catalyst (ID No. C32) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S35) (A/N 366146) No 3-1/3-2.

1,991 MMBTU/HR Gas Turbine (ID No. D36) (A/N 366149) No. 4-3 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW Electric Generator (ID No. B37) and a Heat Recovery Steam Generator (ID No. B38) with 135 MMBTU/HR Duct Burners (ID No. D39) connected in common with Gas Turbine No. 4-4 to a 214.5 MW steam turbine (ID No. B40). Selective Catalytic Reduction (ID No. C42) (A/N 366153) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B43) and a CO oxidation catalyst (ID No. C41) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53) (A/N 366149) No 4-3/4-4.

1,991 MMBTU/HR Gas Turbine (ID No. D45) (A/N 366150) No. 4-4 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW Electric Generator (ID No. B46) and a Heat Recovery Steam Generator (ID No. B47) with 135 MMBTU/HR Duct Burners (ID No. D48) connected in common with Gas Turbine No. 4-3 to a 214.5 MW steam turbine (ID No. B49). Selective Catalytic Reduction (ID No. C51) (A/N 366154) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B52) and a CO oxidation catalyst (ID No. C50) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53) (A/N 366149) No 4-3/4-4.

AQ-1 During the final phase of construction, the operator shall be allowed to exceed normal operational and startup emission limits and operational constraints (**AQ-9, AQ-10, AQ-11, AQ-12, AQ-13** and **AQ-14**) and will be subject only to the limit prescribed in this Condition so that the turbine systems and controls can be fine tuned. This phase of construction is referred to herein as initial commissioning and shall be limited to no more that 66 days duration following the date natural gas is first fired in any one of the four gas turbines.

If the turbine is loaded below 60%, the NOx emission limit is 356 lbs/mmcf. If the turbine is loaded at or above 60%, the NOx emission limit is 64 lbs/mmcf. The total NOx emissions during initial commissioning shall not exceed 69,284 lbs. No more than two turbine systems shall be in initial commissioning at one time. The project owner shall provide written notification to the District and California Energy Commission of the exact date natural gas is first fired in any one of the four turbines. This date is referred to herein as first fire.

Verification: The project owner and/or operator (project owner) shall report the turbine loading conditions (as a percent of maximum), duration of loading conditions (hours), natural gas fuel consumption during loading conditions (mmcf) and total NOx emissions during loading conditions (lbs) from initial commissioning to the California Energy Commission Compliance Project Manager (CPM) for the four gas turbines and duct burners no later than 10 days following the termination of the initial commissioning period.

AQ-2 During the first 12 months of operation immediately following first fire, the project owner shall either (1) limit the annual natural gas fuel consumption for all four gas turbines and all four duct burners to no more than 35,000 MMCF or (2) demonstrate to the satisfaction of the South Coast Air Quality Management District (District) and the CPM that the total NOx emissions from all four gas turbines and duct burners will not exceed 250,302 pounds.

Verification: The project owner shall submit total NOx emissions and natural gas fuel consumption reports to the CPM for the four gas turbines and duct burners as part of the Quarterly Operational Reports as described in Condition **AQ-8**.

AQ-3 The project owner shall install and maintain a continuous monitoring and recording system capable of measuring at least once every 15 minutes and recording measurements at least once every hour to accurately indicate the ammonia injection rate of the ammonia injection system.

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB), the United States Environmental Protection Agency (EPA) and the California Energy Commission (Commission).

AQ-4 The owner shall install and maintain a temperature gauge to accurately measure and record the temperature in the SCR catalyst.

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-5 The project owner shall install, maintain and operate a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to measure CO concentration in ppmv corrected to 15% oxygen on a dry basis and convert those CO concentrations to mass emission rates in units of pounds per hour (lbs/hr). The CEMS shall be capable of measuring at least over a 15-minute averaging period and shall record hourly mass emission rates on a continuous basis. The CEMS shall be installed and operated in accordance with an approved District Rule 218 CEMS plan application. The CEMS plan shall include a requirement for on going relative accuracy testing. The project owner shall NOT install the CEMS prior to receiving initial approval from the District.

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission. The owner shall submit to the CPM a copy of the CEMS plan application submitted to the District and the initial written approval for installation from the District.

AQ-6 The project owner shall install, maintain and operate a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to continuously measure the concentrations of NOx and oxygen in ppmv, fuel flow rate, and operational status codes as defined in District Rule 2012 once every 15 minutes. In compliance with District Rule 2012, the project owner shall at least annually test the NOx CEMS for relative accuracy. The CEMS will convert the NOx concentrations to mass emissions and record NOx mass emissions hourly and daily. The CEMS shall be installed and operating no later than 12 months following first fire (District Rule 2021(h)(6)). From the time of first fire until the CEMS are certified, the project owner shall comply with the fuel monitoring requirements of District Rule 2012(h)(2) and 2012(h)(3).

<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-7 The project owner shall electronically report total daily mass emissions of NO_x and daily operational status codes to the District Central NO_x Station in compliance with District rule 2012 (c)(3)(A). The project owner shall submit to the District Monthly Emissions Reports in the manner and form specified by the District within 15 calendar days of the close of each of the first eleven months of the compliance year (District Rule 2012(c)(3)(B)). The Monthly Emissions Report will include mass emissions of NOx on a monthly, daily and hourly basis within the reporting period.

<u>**Verification:**</u> The project owner shall submit the Monthly Emissions Report to the CPM as part of the Quarterly Operational Report (see **AQ-8**).

AQ-8 The project owner shall submit to the Commission, Quarterly Operational Reports that include the fuel use associated with each gas turbine train (both gas turbine and duct burner), in addition to the CO and NOx CEMS recorded data for each gas turbine exhaust stack (see **AQ-5** and **AQ-6**) on an hourly basis.

<u>**Verification:**</u> The project owner shall submit the Quarterly Operational Reports as specified herein to the CPM no later than 30 days following the end of each calendar quarter.

AQ-9 The project owner shall vent the gas turbine and duct burners to the SCR control whenever the turbines or duct burners are in operation, including startup and normal operation. The gas turbines shall not begin startup (defined as including the purge cycle) until the SCR has been preheated to a temperature of at least 500°F.

Verification: The project owner shall submit SCR temperature recordings (see **AQ-4**) for each startup for each gas turbine in the Quarterly Operational Reports (see **AQ-8**).

AQ-10 Startup is defined as beginning when the SCR of two gas turbines connected to a common steam turbine have reach 500 °F (see **AQ-9**) and ending when both gas turbines have reached stable operational conditions. Shutdown is defined as beginning at normal operating temperatures for two gas turbines connected to a common steam turbine and ending at the secession of fuel burning for both gas turbines. No more than two gas turbines shall be in startup mode at one time. Startup and shutdown shall not exceed 3 hours in duration per day. While any gas turbine is in startup mode, the NOx emissions from all four turbines combined shall be limited to 75.54 lbs/hr. While any gas turbine is in startup mode, the NOx and CO emission limits in Condition **AQ-11** shall not apply.

Verification: The project owner shall submit fuel use, NOx emissions and operational status on an hourly basis during each startup or shutdown for each gas turbine in the Quarterly Operational Reports (see **AQ-8**).

AQ-11 Except during startup, shutdown and initial commissioning, emission from each gas turbine exhaust stack shall not exceed the following limits:

NOx (measured as NO_2):	2.5 ppm at 15% oxygen on a dry basis averaged over one hour and 17.77 lbs/hour.
CO:	6 ppm at 15% oxygen on a dry basis averaged over 3 hours and 25.91 lbs/hr.
SOx (measured as SO_2):	0.67 lbs/mmscf
VOC:	1.64 lbs/mmscf
PM10:	5.21 lbs/mmscf
Ammonia:	5 ppm at 15% oxygen on a dry basis.

Verification: The project owner shall submit emission calculations to demonstrate compliance for the NOx and CO limits in the Quarterly Operational Reports (see **AQ-8**) and source tests, as required in Condition **AQ-15, AQ-16** and **AQ-17**, to demonstrate compliance with SOx, VOC and PM10 emission limits.

AQ-12 Except for initial commissioning, but including startup and shutdowns, the emissions from each gas turbine exhaust stack shall not exceed the following limits:

CO	8,610 lbs per month
VOC	2,498 lbs per month
PM10	7,725 lbs per month
SOx	1,005 lbs per month

Protocol:
The project owner shall confirm compliance with the monthly limits by using the monthly fuel use data of each gas turbine and duct burner pair and the following emission factors:

SOx (measured as SO2):	0.67 lbs/mmscf
VOC:	1.64 lbs/mmscf
PM10:	5.21 lbs/mmscf

Compliance with the CO monthly limit shall be confirmed through the CO CEMS.

<u>**Verification:**</u> The project owner shall submit the monthly fuel use data and emission calculations to the CPM in the Quarterly Operation Reports (**AQ-8**).

AQ-13 Except for initial commissioning, but including startup and shutdowns, the emissions from each gas turbine exhaust stack shall not exceed the following limits:

NOx (measured as NO2): 2 ppm at 15% oxygen averaged over a year and 125.15 tons per year.

<u>**Verification:**</u> The project owner shall submit all necessary data and emission calculations electronically to the CPM in the fourth Quarter Operation Report only (**AQ-8**) to verify compliance of the annual emission limits including the identification of all RECLAIM Trading Credits purchased to offset the facility NOx emissions.

AQ-14 Except for initial commissioning, but including startup and shutdowns, the emissions from each gas turbine exhaust stack shall not exceed the following limits:

PM10: Either 11 lbs/hr or 0.01 grains per standard cubic foot at 3% oxygen averaged over 15 consecutive minutes (or other averaging period specified by the District)

Verification: The project owner shall submit source tests as required by Condition **AQ-17** confirming verification of the condition.

AQ-15 The project owner shall conduct an initial source test of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the Commission 45 days prior to the proposed initial source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- The source test shall be conducted within 60 days of the approval of the source test protocol by the District, but no later than 180 days following the date of first fire.
- The District and Commission shall be notified at least 10 days prior to the date and time of the source test.
- The initial source test shall be conducted with the gas turbine operating under loads of 50%, 75% and 100% of maximum.
- The initial source test shall be conducted to determine the oxygen levels in the exhaust.
- The initial source test shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The initial source test shall be conducted for the pollutants listed using the methods and averaging times indicated.

Pollutant	Method	Averaging Time
NOx	District Method 100.1	1 hour
CO	District Method 100.1	1 hour
SOx	District Method 100.1	1 hour
ROG	District approved method	1 hour
PM10	District approved method	1 hour
Ammonia	District approved method	1 hour

- The initial source test results shall be submitted to the District and the Commission no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
    1. ppmv corrected to 15% oxygen,
    2. pounds per hour,
    3. pounds per million cubic feet of fuel burned and
    4. additionally, for PM10 only, grains per dry standard cubic feet of fuel burned.

Verification: The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time.

AQ-16 The project owner shall conduct source testing of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the Commission no later than 60 days prior to the proposed source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted quarterly.
- Source testing shall be conducted to determine the ammonia emissions from each gas turbine exhaust stack using an approved District method measured over a 1 hour averaging period.
- The District and Commission shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the District and Commission within 45 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- All emission data is to be expressed in the following units:
    1. ppmv corrected to 15% oxygen,
    2. pounds per hour,
    3. pounds per million cubic feet of fuel burned and

Verification: The project owner shall submit the proposed protocol for the source tests 60 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 7 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.

AQ-17 The project owner shall conduct source testing of each gas turbine exhaust stack to verify compliance with the PM10 emission limits stated in Condition **AQ-14**, in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the Commission 60 days prior to the proposed initial source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted to measure PM10 emissions from each gas turbine exhaust stack using District Method 5.1.
- Source testing shall be conducted using natural gas operating at minimum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The source test shall be conducted no later than 6 months after this time limit has been exceeded.
- Source testing shall be conducted using natural gas operating at maximum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The source test shall be conducted no later than 6 months after this time limit has been exceeded.
- Source testing frequency shall be annual, but may be reduced to once every 5 years under the highest emitting load if three consecutive annual test results show compliance condition **AQ-14**.
- Source testing shall not be required for any one year for which the equipment is not in operation.
- Source test shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- Source test results shall be submitted to the District and the Commission no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
  1. pounds per hour,
  2. pounds per million cubic feet of fuel burned and
  3. grains per dry standard cubic feet of fuel burned.

Verification: The project owner shall submit the proposed protocol for the source tests 60 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

The following Conditions of Certification pertain to the following equipment: Internal combustion engine, emergency power , diesel Caterpillar 3612, 4^0 timing retard, turbocharged, aftercooled, 5900 BHP A/N 366155 (ID. No. D54).

AQ-18 The project owner shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-21**).

AQ-19 The project owner shall set and maintain the fuel injection timing of the emergency IC engine at 4^0 retarded relative to standard timing.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-20 The project owner shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the emergency IC engine.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-21 The project owner shall maintain records in a manner approved by the District for the following parameters or items in regards to the emergency IC engine:

- Date of operation,
- elapsed time of operation (in hours) and
- the reason for operation.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-22 The project owner shall use the emergency IC engine only during utility failure periods, except for maintenance purposes.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-21**).

AQ-23 The project owner shall limit the operating time of the emergency IC engine to no more than 200 hours per year.

Verification: The project owner shall submit the recorded data specified in condition **AQ-21** on an annual basis as part of the fourth Quarter Operational Report (see **AQ-8**).

The following Conditions of Certification pertain to the following equipment: Internal combustion engine, emergency fire pump, diesel Cummins 6BTA, 4^0 timing retard, turbocharged, aftercooled, 182 BHP A/N 366156 (ID. No. D55).

AQ-24 The project owner shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-27**).

AQ-25 The project owner shall set and maintain the fuel injection timing of the fire pump IC engine at 4^0 retarded relative to standard timing.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-26 The project owner shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the fire pump IC engine.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-27 The project owner shall maintain records in a manner approved by the District for the following parameters or items in regards to the fire pump IC engine:

- Date of operation,

- elapsed time of operation (in hours) and
- the reason for operation.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-28 The project owner shall limit the operating time of the fire pump IC engine to no more than 200 hours per year.

Verification: The project owner shall submit the recorded data specified in condition **AQ-27** on an annual basis as part of the fourth Quarter Operational Report (see **AQ-8**).

The following Conditions of Certification pertain to the following equipment:
The two cooling towers associated with the new gas turbine units (Units 3 and 4), each are 147,000 gal/min in capacity, have 10 cells, two rows side-by-side, forced vent and have a drift rate of 0.0006%.

The two cooling towers associated with the existing boilers units (Units 1 and 2), each are 38,700 gal/min in capacity, have 4 cells, inline, forced vent and have a drift rate of 0.0006%.

AQ-29 The project owner shall submit drift eliminator design details and vendor specific justification for the correction factor to be used to correlate blowdown TDS to drift TDS and the amount of drift that stays suspended in the atmosphere in the equation in Condition **AQ-34** to the Commission at least 30 days prior to commencement of construction.

Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the CPM.

AQ-30 The project owner shall submit cooling tower design details including the cooling tower type and materials of construction to the Commission at least 30 days prior to commencement of construction, and at least 90 days before the tower is operated.

Verification: The project owner shall submit the information required above to the CPM 30 days prior to the commencement of construction of the cooling towers.

AQ-31 The project owner shall NOT use hexavalent chromium containing compounds in the cooling tower circulating water.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA or the Commission.

AQ-32 The project owner shall design and build the cooling towers such that the drift eliminator drift rate of the cooling towers does not exceed 0.0006%.

Verification: The project owner shall submit documentation from the selected cooling tower vendor that verifies the drift efficiency to the CPM 30 days prior to commencement of construction of the cooling towers.

AQ-33 The project owner shall limit the PM10 emissions from the cooling towers as follows:

Each 10 cell cooling tower is not to exceed 70.1 lbs/day.
Each 4 cell cooling tower is not to exceed 18.5 lbs/day.

Verification: The project owner shall submit data and calculations on annual basis to the CPM as discussed in condition **AQ-34**.

AQ-34 The project owner shall demonstrate compliance with the PM10 daily emission limit (see **AQ-33**) as follows:

PM10 lb/day = circulating water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate * correction factor.

Verification: The project owner shall compile the required data on a daily basis and submit the data and calculations annually in the fourth Quarter Operational Report (see **AQ-8**) to the CPM.

AQ-35 The project owner shall perform circulating water sample analyses by independent laboratory within 90 days of initial operation and weekly thereafter to determine the TDS within the cooling tower water.

Verification: The project owner shall compile the required analyses and maintain the data on site for a minimum period of two years. The project owner shall make the site available for inspection by representatives of the District, CARB, EPA or the Commission.

The following Conditions of Certification pertain to all devices which produce criteria air emission (NOx, SOx, CO and PM10):

AQ-36 The gas turbines shall not be operated unless the operator demonstrates to the District that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, the gas turbines shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

<u>**Verification:**</u> The project owner shall submit records of all RTCs, including the initial allocation to the existing boilers, deposited for the Mountainview facility to the CPM in the fourth Quarterly Operational Report (see **AQ-8**).

AQ-37 Except for open abrasive blasting operations, the project owner shall shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or
(b) Of such opacity as to obscure an observer s view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA or the Commission.

AQ-38 The project owner shall limit the Acid Rain SO2 Allowance for the affected units as follows:

Device ID	Boiler ID	Contaminant	Tons in any year
D1	Boiler Unit No. 1	SO2	117
D2	Boiler Unit No. 2	SO2	17

<u>**Verification:**</u> The project owner shall demonstrate compliance through the submittal of Quarterly Operational Reports as required by condition **AQ-8**.

The following Conditions of Certification pertain to the following equipment:
Boiler Unit No. 1, Natural gas combustion engineering, eight burners, Peabody, 680 MMBtu/hr with generator, 63 MW. A/N 368336 (ID No. D1).

Boiler Unit No. 2, Natural gas combustion engineering, eight burners, Peabody, 680 MMBtu/hr with generator, 63 MW. A/N 368334 (ID No. D2).

AQ-39 The project owner shall burn only natural gas containing sulfur compounds calculated as H_2S in excess of 16 parts per million by volume (ppmv) or cause CO emissions to exceed 2,000 ppm by volume measured on a dry basis, averaged over 15 consecutive minutes in either boiler unit 1 or 2.

Verification: The project owner shall maintain appropriate records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-40 The project owner shall not discharge into the atmosphere from the burning of fuel, combustion contaminants exceeding 0.23 gram per cubic meter (0.1 grain per cubic foot) of gas calculated to 12 percent of carbon dioxide (CO2) at standard conditions averaged over a minimum of 15 consecutive minutes.

Verification: The project owner shall maintain appropriate records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-41 The project owner shall install, maintain and operate a direct monitoring device (CEMS) for each boiler exhaust stack to continuously measure the concentration of NO_x emissions and all other applicable variables specified in District Rule 2012. In compliance with District Rule 2012, the project owner shall at least annually test the NOx CEMS for relative accuracy. The CEMS will convert the NOx concentrations to mass emissions and record NOx mass emissions hourly and daily. The CEMS shall electronically report total daily mass emissions of NO_x and daily status codes to the District Central NO_x Station for each boiler exhaust stack.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-42 The project owner shall submit to the Commission, Quarterly Operational Reports that include the fuel use associated with each boiler unit, in addition to the NOx CEMS recorded data for each boiler exhaust stack (see **AQ-41**) on an hourly basis.

__Verification:__ The project owner shall submit the Quarterly Operational Reports to the CPM no later than 30 days following the end of each calendar quarter (see **AQ-8**).

AQ-43 Immediately following the completion of initial commissioning of all four gas turbines, the project owner shall limit the emissions of NOx from both boilers systems, Units 1 and 2 combined, to no more than 65.3 lbs/hr during all modes of operation, including startup and shutdown.

__Verification:__ The project owner shall submit emission calculations and records from the existing CEMS on the boiler systems, Units 1 and 2, to demonstrate compliance for the NOx limit in the Quarterly Operational Reports (see **AQ-8**).

AQ-44 The project owner shall submit designs and vendor guarantees for any emission control systems or measures intended to reduce NOx emissions from the existing boiler systems, Units 1 and 2, to meet the emission limits specified in Condition **AQ-43**.

__Verification:__ The project owner shall submit the identified designs and vendor guarantees to the CPM for approval, no later than 30 days prior to the completion of initial commissioning of the four proposed gas turbines. The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

The following Conditions of Certification pertain to the following equipment:
Storage tank, TK-1, serving SCRs 3-1 and 3-2 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366162 (ID No. D56).

Storage tank, TK-2, serving SCRs 4-3 and 4-4 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366163 (ID No. D57).

AQ-45 The project owner shall vent the aqueous ammonia storage tank during filling procedures only to the vessel from which it is being filled.

__Verification:__ The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-46 The project owner shall install and maintain a pressure relief valve set at 25 psig in the aqueous ammonia storage tank.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

The following Conditions of Certification pertain to the following equipment: Storage tank, underground, gasoline with vapor lock balance recovery system, 2000 gallons A/N 364670 (ID No. D7).

Fuel dispensing nozzle, balance type phase II control, gasoline A/N 364670 (ID No. D8).

AQ-47 The project owner shall ensure that the gasoline storage tank and dispensing nozzle comply with District Rule 461.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-48 The project owner shall use the phase I vapor recovery system in full operation whenever the gasoline storage tank is in use. This system shall be installed, operated and maintained to meet all CARB certification requirements.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-49 The project owner shall use the phase II vapor recovery system in full operation whenever gasoline from the gasoline storage tank is dispensed to motor vehicles as defined in District Rule 461. This system shall be installed, operated and maintained to meet all CARB certification requirements.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-50 The project owner shall have a person trained in accordance with District Rule 461 (c)(6) conduct a semi-annual inspection of the gasoline transfer and dispensing equipment. The first inspection shall be in accordance with District Rule 461, Attachment C, the second inspection shall be in accordance with District Rule 461, Attachment D, and the subsequent inspections shall alternate protocols. The operator shall keep records of the inspection and the repairs in accordance to District Rule 461 and Section K of the District Permit to Operate for the gasoline storage tank.

<u>**Verification:**</u> The project owner shall maintain records on site and make them available for inspection by representatives of the District, CARB, EPA and the Commission.

The following Conditions of Certification pertain to the following equipment:
Abrasive blasting equipment, Glove box <= 53 C Ft with dust filter (ID No. E14)

Oil water separators, gravity type, <45 Sq. Ft air liquid interface area (ID No. E15)

Coating equipment, portable architectural coatings (ID No. E16)

AQ-51 The project owner shall keep records in manner approved by the District for the following parameters or items concerning the abrasive blasting equipment:

- The name of the person performing the inspection and/or maintenance of the dust collector,
- The date, time and results of the inspection, and
- The date time and description of any maintenance or repairs resulting from the inspection.

<u>**Verification:**</u> The project owner shall maintain records on site and make them available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-52 The project owner shall perform annual inspections of the abrasive blasting equipment and filter media for leaks, broken or torn filter media, and improperly installed filter media.

<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-53 The project owner shall conduct an inspection for visible emissions from all points of the abrasive blasting equipment whenever these is a public complaint of visible emissions, whenever visible emissions are observed, and on an annual basis, at least, unless the equipment did not operate during the entire annual period. The routine annual inspection shall be conducted while the equipment is in operation and during daylight hours. If any visible emissions (not including condensed water vapor) are detected, the operator shall take corrective action(s) that eliminates the visible emissions within 24 hours and report the visible emissions as a potential deviation in accordance with the reporting requirements in Section K of the Permit to Operate for the Mountainview Facility.

The project owner shall keep the records in accordance with the record keeping requirements in Section K of the Permit to Operate of the Mountainview Facility and the following records:

- Stack or emission point identification
- Description of any corrective actions taken to abate visible emissions; and
- Date and time visible emission was abated.

<u>**Verification:**</u> The project owner shall maintain records on site and make them available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-54 The project owner shall ensure that the oil water separators comply with District Rule 464.

<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-55 The project owner shall keep records in a manner approved by the District for the following parameters or items concerning the portable coating equipment:

For architectural applications where no thinners, reducers or other VOC containing materials are added, maintain semi-annual record for all coatings consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvents for other coatings.

For architectural applications where thinners, reducers or other VOC containing materials are added, maintain daily record for all coatings consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvents for other coatings.

<u>**Verification:**</u> The project owner shall maintain records on site and make them available for inspection by representatives of the District, CARB, EPA and the Commission.

REFERENCES

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APPENDIX A

CALCULATIONS OF SECONDARY PM10 IMPACTS

Staff proposes to use the equation below as the basis for predicting the potential secondary PM10 formation from the ammonia slip emissions at the MVPP.

$$AN = \_ \{TA + TN — [(TA+TN)^2 — 4(TA*TN-K_p)]^{1/2}\} \text{ (Seinfeld 1986)}$$

$$TN = N_g + N_a$$

$$TA = A_g + A_a$$

$$A_g = TA — AN$$

$$N_g = TN - AN$$

Where
AN = Total ammonium nitrate formed
TA = Total ammonia available to form ammonium nitrate
TN = Total nitrate available to form ammonium nitrate
K_p = Equilibrium dissociation constant for pure ammonium nitrate
N_g = Gaseous nitric acid concentration
N_a = Aerosol nitrate
A_g = Gaseous ammonia concentration
A_a = Aerosol ammonium concentration

The components that were measured by the District in a 1995 dairy impact study that can be incorporated into these equations are the gaseous nitric acid (N_g), aerosol nitrate (N_a), gaseous ammonia (A_g) and the aerosol ammonium (A_a) concentrations. Beginning with these initial states staff would calculate the initial expected ammonium nitrate concentration (AN). Then staff would increase the A_g concentration by the amount that the power plant s predicted maximum ammonia impact. By using an iterative process, staff would solve each of the above equations to eventually derive the predicted MVPP impact on ammonium nitrate formation. These results would have to be restricted to an annual average as the nitrate formation reaction is very dependent on ambient conditions. Staff intends to make these calculations available at a later date.

APPENDIX B

DETAILED EMISSION CALCULATIONS

Mountianview Power Project

Basic Emission Factors for short term only

Equipment	Operation	lbs/hr NOx	SOx	CO	VOC	PM10
CTG Turbine	Full Load w/duct 102 deg F	16.37	1.31	23.92	3.19	11
	Full Load w/duct 82 deg F	16.64	1.33	24.32	3.24	11
	Full Load w/o duct 59 deg F	16.03	1.28	23.37	3.12	11
	Full Load w/o duct 30 deg F	16.59	1.32	24.2	3.24	11
	Full Load w/duct 30 deg F	17.77	1.42	25.91	3.47	11
	Cold start	20	0.86	50	3.47	10.38
	Warm start	20	0.86	62.5	3.47	10.38
	Hot start	20	0.86	100	3.47	10.38
CTG Cooling Tower	Full Load					2.92
	Startup					2.92
Boiler	Full Load	32.64	0.68	2.04	0.68	0.2
	Startup	2.51	0.05	0.16	0.05	0.02
Boiler Cooling Tower	Full Load					0.77
	Startup					0.06
Emergency IC Engine	Full Load	19.8	0.44	1.56	1.56	0.81
Firewater Pump	Full Load	1.98	0.063	0.53	0.31	0.1

Basic Emission Factors for long term only

	Temperature	Duct	lb/hr NOx (see 1)	SOx	CO (see 2)	VOC	PM10
CTG Turbine @ full load	102	on	6.56	1.31	7.98	3.19	11
	82	on	6.66	1.33	8.11	3.24	11
	59	off	6.38	1.28	7.8	3.12	11
	59	on		1.37	8.34	3.34	11
	30	off	6.62	1.32	8.06	3.24	11
	30	on	7.13	1.42	8.65	3.47	11

Note: Boiler and Cooling tower emissions are the same as shortterm

1 NOx emissions assume an annual average of 1.0 ppm

2 CO emissions assume an annual average of 2.0 ppm

Mountainview Power Project - Startup Calculations

				pounds				
		Blackstart	Duration	NOx	SOx	CO	VOC	PM10
	Full Load	IC Eng.	3	59.40	1.32	4.68	4.68	2.43
	Start	Boiler 1	3	7.53	0.15	0.48	0.15	0.06
		Boiler 2	3	7.53	0.15	0.48	0.15	0.06
		Boiler CT 1	3	0.00	0.00	0.00	0.00	0.18
		Boiler CT 2	3	0.00	0.00	0.00	0.00	0.18
	Full Load	Boiler 1	6	195.84	4.08	12.24	4.08	1.20
		Boiler 2	6	195.84	4.08	12.24	4.08	1.20
		Boiler CT 1	6	0.00	0.00	0.00	0.00	4.62
		Boiler CT 2	6	0.00	0.00	0.00	0.00	4.62
	Start	CTG U1 T1	3	60.00	2.58	150.00	10.41	31.14
		CTG U1 T2	3	60.00	2.58	150.00	10.41	31.14
No Duct	Full Load	CTG U1 T1	3	49.77	3.96	72.60	9.72	33.00
		CTG U1 T2	3	49.77	3.96	72.60	9.72	33.00
	Start	CTG U2 T1	3	60.00	2.58	150.00	10.41	31.14
		CTG U2 T2	3	60.00	2.58	150.00	10.41	31.14
	Full Load &	CTG CT1	6	0.00	0.00	0.00	0.00	17.52
	Start	CTG CT2	3	0.00	0.00	0.00	0.00	8.76
		TOTAL	**9**	**805.68**	**28.02**	**775.32**	**74.22**	**231.39**
		Ave. lb/hr		89.52	3.11	86.15	8.25	25.71

		Cold Start						
	Full Load	Boiler 1	6	195.84	4.08	12.24	4.08	1.20
		Boiler 2	6	195.84	4.08	12.24	4.08	1.20
		Boiler CT 1	6	0.00	0.00	0.00	0.00	4.62
		Boiler CT 2	6	0.00	0.00	0.00	0.00	4.62
	Start	CTG U1 T1	3	60.00	2.58	150.00	10.41	31.14
		CTG U1 T2	3	60.00	2.58	150.00	10.41	31.14
No Duct	Full Load	CTG U1 T1	3	49.77	3.96	72.60	9.72	33.00
		CTG U1 T2	3	49.77	3.96	72.60	9.72	33.00
	Start	CTG U2 T1	3	60.00	2.58	150.00	10.41	31.14
		CTG U2 T2	3	60.00	2.58	150.00	10.41	31.14
	Full Load &	CTG CT1	6	0.00	0.00	0.00	0.00	17.52
	Start	CTG CT2	3	0.00	0.00	0.00	0.00	8.76
		TOTAL	**6**	**731.22**	**26.40**	**769.68**	**69.24**	**228.48**
		Ave. lb/hr		121.87	4.40	128.28	11.54	38.08

		Warm Start						
	Full Load	Boiler 1	4	130.56	2.72	8.16	2.72	0.80
		Boiler 2	4	130.56	2.72	8.16	2.72	0.80
		Boiler CT 1	4	0.00	0.00	0.00	0.00	3.08
		Boiler CT 2	4	0.00	0.00	0.00	0.00	3.08
	Start	CTG U1 T1	2	40.00	1.72	125.00	6.94	20.76
		CTG U1 T2	2	40.00	1.72	125.00	6.94	20.76
No Duct	Full Load	CTG U1 T1	2	33.18	2.64	48.40	6.48	22.00
		CTG U1 T2	2	33.18	2.64	48.40	6.48	22.00
	Start	CTG U2 T1	2	40.00	1.72	125.00	6.94	20.76
		CTG U2 T2	2	40.00	1.72	125.00	6.94	20.76
	Full Load &	CTG CT1	4	0.00	0.00	0.00	0.00	11.68
	Start	CTG CT2	2	0.00	0.00	0.00	0.00	5.84
		TOTAL	**4**	**487.48**	**17.60**	**613.12**	**46.16**	**152.32**
		Ave. lb/hr		81.25	2.93	102.19	7.69	25.39

		Hot Start						
	Full Load	Boiler 1	2	65.28	1.36	4.08	1.36	0.40
		Boiler 2	2	65.28	1.36	4.08	1.36	0.40
		Boiler CT 1	2	0.00	0.00	0.00	0.00	1.54
		Boiler CT 2	2	0.00	0.00	0.00	0.00	1.54
	Start	CTG U1 T1	1	20.00	0.86	100.00	3.47	10.38
		CTG U1 T2	1	20.00	0.86	100.00	3.47	10.38
No Duct	Full Load	CTG U1 T1	1	16.59	1.32	24.20	3.24	11.00
		CTG U1 T2	1	16.59	1.32	24.20	3.24	11.00
	Start	CTG U2 T1	1	20.00	0.86	100.00	3.47	10.38
		CTG U2 T2	1	20.00	0.86	100.00	3.47	10.38
	Full Load &	CTG CT1	2	0.00	0.00	0.00	0.00	5.84
	Start	CTG CT2	1	0.00	0.00	0.00	0.00	2.92
		TOTAL	**2**	**243.74**	**8.80**	**456.56**	**23.08**	**76.16**
		Ave. lb/hr		121.87	4.40	228.28	11.54	38.08

Max Hourly Emissions

Second Turbine Cold Start			Pounds				
		Duration	NOx	SOx	CO	VOC	PM10
Full Load	Boiler 1	1	32.64	0.68	2.04	0.68	0.20
	Boiler 2	1	32.64	0.68	2.04	0.68	0.20
	Boiler CT 1	1	0.00	0.00	0.00	0.00	0.77
	Boiler CT 2	1	0.00	0.00	0.00	0.00	0.77
Full Load	CTG U1 T1	1	17.77	1.42	25.91	3.47	11.00
	CTG U1 T2	1	17.77	1.42	25.91	3.47	11.00
Start	CTG U2 T1	1	20.00	0.86	50.00	3.47	10.38
	CTG U2 T2	1	20.00	0.86	50.00	3.47	10.38
	CTG CT1	1	0.00	0.00	0.00	0.00	2.92
	CTG CT2	1	0.00	0.00	0.00	0.00	2.92
	TOTAL	**1**	140.82	5.92	155.90	15.24	50.54
	turbines only		75.54	4.56	151.82	13.88	48.60

Max Daily Emissions

Cold Start Day			Pounds				
Full Load	Boiler 1	24	783.36	16.32	48.96	16.32	4.80
	Boiler 2	24	783.36	16.32	48.96	16.32	4.80
	Boiler CT 1	24	0.00	0.00	0.00	0.00	18.48
	Boiler CT 2	24	0.00	0.00	0.00	0.00	18.48
Start	CTG U1 T1	3	60.00	2.58	150.00	10.41	31.14
	CTG U1 T2	3	60.00	2.58	150.00	10.41	31.14
Full Load	CTG U1 T1	21	373.17	29.82	544.11	72.87	231.00
	CTG U1 T2	21	373.17	29.82	544.11	72.87	231.00
Start	CTG U2 T1	3	60.00	2.58	150.00	10.41	31.14
	CTG U2 T2	3	60.00	2.58	150.00	10.41	31.14
Full Load	CTG U2 T1	18	319.86	25.56	466.38	62.46	198.00
	CTG U2 T2	18	319.86	25.56	466.38	62.46	198.00
	CTG CT1	24	0.00	0.00	0.00	0.00	70.08
	CTG CT2	21	0.00	0.00	0.00	0.00	61.32
	IC Engine	1	19.80	0.44	1.56	1.56	0.81
	TOTAL	24	3,212.58	154.16	2,720.46	346.50	1,161.33
			1,645.86	121.52	2,622.54	313.86	1,114.77

Maximum Annual Emissions

Equipment	Operation	Temperature	Duct	Duration	NOx	SOx	CO	VOC	PM1
					Tons				
Turbine	Startup	Hot	off	233	2.33	0.10	11.65	0.40	1.2
		Warm	off	96	0.96	0.04	3.00	0.17	0.5
		Cold	off	36	0.36	0.02	0.90	0.06	0.1
	Full Load	102	on	20	0.07	0.01	0.08	0.03	0.1
		82	on	850	2.83	0.57	3.45	1.38	4.6
		59	off	3605	11.50	2.31	14.06	5.62	19.8
		30	off	2875	9.52	1.90	11.59	4.66	15.8
		30	on	1045	3.73	0.74	4.52	1.81	5.7
			Subtotal	**8760**	**31.29**	**5.68**	**49.24**	**14.14**	**48.0**
CTG Cooling Tower	Startup			365					0.5
	Full Load			8395					12.2
			Subtotal	**8760**	**0.00**	**0.00**	**0.00**	**0.00**	**12.7**
Boiler Unit 1	Startup			1495	1.88	0.04	0.12	0.04	0.0
	Full Load			2500	40.80	0.85	2.55	0.85	0.2
			Subtotal	**3995**	**42.68**	**0.89**	**2.67**	**0.89**	**0.2**
Boiler Cool Tw. 1	Startup			1495					0.0
	Full Load			2500					0.9
			Subtotal	**3995**	**0.00**	**0.00**	**0.00**	**0.00**	**1.0**
Boiler Unit 2	Startup			819	1.03	0.02	0.07	0.02	0.0
	Full Load			1200	19.58	0.41	1.22	0.41	0.1
			Subtotal	**2019**	**20.61**	**0.43**	**1.29**	**0.43**	**0.1**
Boiler Cool Tw. 2	Startup			819					0.0
	Full Load			1200					0.4
			Subtotal	**2019**	**0.00**	**0.00**	**0.00**	**0.00**	**0.4**
Emergecy IC Engine	Full Load			200	1.98	0.04	0.16	0.16	0.0
Firewater Pump	Full Load			200	0.20	0.01	0.05	0.03	0.0

Summary Table

Equipment	**Number**	**NOx**	**SOx**	**CO**	**VOC**	**PM1**
		Tons/year				
Turbines Unit 1-4	4	125.15	22.73	196.97	56.55	192.
Boiler Unit 1	1	42.68	0.89	2.67	0.89	0.2
Boiler Unit 2	1	20.61	0.43	1.29	0.43	0.1
Cooling Towers	4	0.00	0.00	0.00	0.00	27.0
Emergency Engine	1	1.98	0.04	0.16	0.16	0.0
Firewater Pump	1	0.20	0.01	0.05	0.03	0.0
Total		**190.62**	**24.09**	**201.14**	**58.05**	**219.**
		1 ppm		*2 ppm*		