San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

DOCKET
06-AFC-10
DATE MAY 0 4 2007
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Che McFarlin
Siting Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Preliminary Determination of Compliance (PDOC)
Project Number: C1063535 – Starwood Power-Midway, LLC (06-AFC-10)

Dear Mr. McFarlin:

Enclosed for your review and comments is the District's preliminary determination of compliance (PDOC) for Starwood Power-Midway, LLC, for the installation of a nominal 120 MW simple cycle, peaking power plant to be located at 43699 W. Panoche Road in Firebaugh, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Dustin Brown of Permit Services at (559) 230-5932.

Sincerely,

for · David Warner
Director of Permit Services

DW:ddb

Enclosures

Fresno Bee

**NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
DETERMINATION OF COMPLIANCE**

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of determination of compliance (DOC) to Starwood Power-Midway, LLC for the installation of a nominal 120 MW simple cycle, peaking power plant, located at 43699 W. Panoche Road in Firebaugh, CA.

The analysis of the regulatory basis for these proposed actions, Project #C-1063535, is available for public inspection at the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.

DETERMINATION OF COMPLIANCE EVALUATION

Starwood Power-Midway Project
California Energy Commission
Application for Certification Docket #: 06-AFC-10

Facility Name:	Starwood Power-Midway, LLC
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Engineer:	Dustin Brown, Senior Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Date:	May 3, 2007
Project #:	C-1063535
Application #'s:	C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0
Submitted:	November 22, 2006

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I. PROPOSAL:

Starwood Power-Midway, LLC, hereinafter referred to as "Starwood Power", is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "peaking" electrical power generation facility. Starwood Power will be a simple-cycle electrical power generation facility consisting of four natural gas-fired combustion turbine generators (CTG's). The plant will have a nominal rating of 120 megawatts (MW) electrical power.

As shown in Section VIII, District Rule 2201 of this document below, Starwood Power will be located next to, is under common ownership, and falls within the same industrial grouping by virtue of falling within the same two-digit standard industrial classification code as the existing Cal Peak Power – Panoche (Facility C-3811) facility. Therefore, for the purposes of this project, these two sources will be considered part of the same stationary source.

Starwood Power is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

Additionally, Starwood Power is subject to Prevention of Significant Deterioration requirements by EPA Region IX.

II. APPLICABLE RULES:

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)
Rule 2010	Permits Required (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)
Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99) Subpart GG - Standards of Performance for Stationary Gas Turbines Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/18/00)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)

Rule 4703 Stationary Gas Turbines (8/17/06)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)
California Environmental Quality Act (CEQA)
California Health & Safety Code (CH&S), Sections 41700 (Health Risk Analysis), 42301.6 (School Notice), and 44300 (Air Toxic "Hot Spots")

III. PROJECT LOCATION:

The proposed equipment will be located within Section 5, Township 15 South, Range 13 East on the United States Geological Survey Quadrangle map. The assessor's parcel number is 027-060-78S. The proposed plant site will occupy approximately 5.6-acres within the existing 128-acre parcel (see site location and layout in Attachment B).

The site is located approximately 20 miles to the south of the city of Firebaugh, in Fresno County, CA. The District has verified that the proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Starwood Power will consist of two Pratt & Whitney, model FT8-3 SwiftPac, Gas Turbine Generator units. Each SwiftPac unit will have two Pratt & Whitney, model FT8-3, natural gas fired turbines that will drive opposite ends of a single electric generator. Each turbine will have the ability to operate independently of any other turbine. Each electric generator will produce electricity at a nominal output of 60 MW. The total facility nominal output will be 120 MW. No cooling towers or heat recovery steam generators (HRSG's) will be installed. In addition, the applicant has not proposed any black start equipment.

The two FT8-3 SwiftPac units will be installed in a simple cycle power plant arrangement. Each CTG is equipped with water injection into the combustors to reduce production of nitrogen oxides (NO_X). The exhaust paths from the two turbines within each SwiftPac merge together in to one common exhaust stack that is vented through a selective catalytic reduction (SCR) system with ammonia injection to further reduce NO_X emissions, an oxidation catalyst to reduce Carbon Monoxide (CO) emissions, and associated support equipment.

The CTG's will operate during periods of peak electricity demand. Peak electricity demand periods typically occur during daylight hours in the second and third quarters of the calendar year, but can also occur during other periods when unusual temperature extremes cause unseasonably high electricity demand or when other electricity resource constraints reduce the amount of power otherwise available to the grid. This facility could operate during any of these periods.

The facility has proposed an annual operating scenario of 3,781 hours of full load operation per year and 219 hours in startup or shutdown mode. Starwood Power does not wish to be restricted to a specific number of hours at full load operation or startup/shutdown operation per calendar quarter. Actual emissions from the facility will vary depending on electricity demand from California. A hypothetical operating scenario has been developed for purposes of demonstrating that the project will comply with SJVAPCD emission offset requirements.

Starwood Power-Midway – Hypothetical Operating Scenario (per unit)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startup/Shutdown Hours	43.8	43.8	76.65	54.75	219
Number of Full Load Hours	756.2	756.2	1,323.35	945.25	3,781
Total Hours	800	800	1,400	1,000	4,000

The CTG's will utilize water injection into the combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.5 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 6.0 ppmvd @ 15% O_2
SO_X: 0.00285 lb/MMBtu (0.89 lb/hr)
PM_{10}: 0.00594 lb/MMBtu (1.85 lb/hr)

Continuous emissions monitoring systems (CEM's) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

V. EQUIPMENT LISTING:

C-7286-1-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-2)

C-7286-2-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-1)

C-7286-3-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-4)

C-7286-4-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-3)

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

Emissions from these natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form a more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Starwood Power has proposed to use an oxidation catalyst to reduce CO emissions in the exhaust gases of these turbines. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

VII. GENERAL CALCULATIONS:

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

All four of the turbines being installed under this project are identical. Therefore, the following general calculations sections will apply to each turbine and separate calculations will not be performed for each turbine individually.

A. Assumptions

- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.

- The commissioning period will not exceed 100 hours and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.

- A SO_X emissions rate of 0.89 lb/hr was calculated using each CTG maximum heat input of 311 MMBtu/hr (@ 100% load) and by performing a mass balance assuming 1,000 Btu/scf (hhv) for natural gas, and a natural gas sulfur content of 1.0 gr S/100 scf.

  $$(1.0\ \cancel{\text{gr S}}/100\ \cancel{\text{dscf}} \times 1\ \cancel{\text{lb S}}/7000\ \cancel{\text{gr}} \times 64\ \text{lb } SO_X/32\ \cancel{\text{lb S}} \times 1\ \cancel{\text{scf}}/1000\ \cancel{\text{Btu}} \times 10^6\ \cancel{\text{Btu}}/\text{MMBtu})$$
  $$= 0.00285\ \text{lb/MMBtu}$$

- Maximum daily emissions for each CTG for NO_X and CO are estimated assuming one (1) hour operating in startup mode, one (1) hour in shutdown mode and twenty two (22) hours operating while firing at full load.

- Maximum daily emissions for each CTG for VOC, PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load.

- Maximum annual emissions for each CTG for NO_X and CO are estimated assuming 109.5 hours operating in startup mode, 109.5 hours in shutdown mode and 3,781 hours operating while firing at full load.

- Maximum annual emissions for each CTG for VOC, PM_{10}, SO_X, and NH_3 are estimated assuming 4,000 hours operating while firing at full load.

- Quarterly emissions are estimate based on the following hypothetical operating schedule:

Starwood Power – Hypothetical Operating Scenario (per unit) (repeated from page 3)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startup/Shutdown Hours	43.8	43.8	76.65	54.75	219
Number of Full Load Hours	756.2	756.2	1,323.35	945.25	3,781
Total Hours	800	800	1,400	1,000	4,000

B. <u>Emission Factors</u>

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C for manufacturer's commissioning period emission data) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	41.65	19.9	N/A[(1)]	N/A[(1)]	N/A[(1)]

The maximum steady state air contaminant mass emission rates (lb/hr) and concentrations (ppmvd @ 15% O_2) estimated by the manufacturer (see Attachment D for manufacturer's emissions data) for the proposed CTG's are summarized below. The worst case NO_X, CO and VOC mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 63.3 °F (worst case ambient temperature per turbine manufacturer). The worst case PM_{10}, SO_X and NH3 mass emission rates are when each turbine operates at 100% load, at any ambient air inlet temperature.

[(1)] VOC, PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

Steady State Maximum Emission Rates and Concentrations						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	2.8	4.19	0.82*	1.85	0.89	4.24**
ppmvd @ 15% O_2 limits	2.5	6.0	2.0	--	--	10.0

*Starwood Power proposed a worst case VOC emission rate of 0.70 lb/hr. However, this hourly emission rates was based on 1.7 ppmvd @ 15% O_2. The proposed turbines will be operating at 2.0 ppmvd @ 15% O_2. Therefore, the proposed hourly emission rate was determined as follows:

VOC PE = (0.70 lb-VOC/hr / 1.7 ppmv) x 2.0 ppmvd
VOC PE = 0.82 lb-VOC/hr

**The proposed ppmvd NH_3 limit was converted to lb/hr using the following equation:

NH_3 PE= ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:

ppm is the emission concentration in ppmvd @ 15% O_2
MW is the molecular weight of the pollutant
MW_{NH3} = 17 lb/lb-mol
2.64×10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas (Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour (MMscf/hour)
O_2 is the stack oxygen content to which the emission concentrations are corrected (3%)

NH_3 PE (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu)
x 1,000 (Btu/scf) x 0.3112 (MMscf/hr) x [20.9 / (20.9 – 15.0)]

The maximum startup and shutdown emissions rates (lb/hr) estimated by the manufacturer (see Attachment D for manufacturer's startup and shutdown emissions data) for the proposed CTG's are summarized below:

Startup Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	4.17	12.5	0.83	N/A(2)	N/A(2)

Shutdown Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	1.50	21.33	0.83	N/A(2)	N/A(2)

(2) PM_{10} and SO_X emissions during startups and shutdowns are typically lower than maximum hourly emissions during baseload facility operation. However, as a worst case, it will be assumed that the emissions for these pollutants will be equivalent to emissions during baseload facility operation.

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.27 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this turbines are new emission units, the pre-project potential to emit (PE1) for all the emissions units associated with this project will be set equal to zero.

2. Post Project Potential to Emit (PE2)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X emissions will occur when each CTG is operating under start-up mode. The maximum hourly potential to emit for CO emissions will occur when each CTG is operating under shutdown mode. Maximum hourly emissions for VOC, PM_{10}, SO_X, and NH_3 will occur when each CTG is operating at full load. The maximum hourly emissions are summarized in the table below:

Maximum Daily Potential to Emit				
	Startup Emissions Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Hourly PE (per CTG) (lb/hr)
NO_X	4.17	1.50	2.80	4.17
CO	12.50	21.33	4.19	21.33
VOC	0.83	0.83	0.82	0.83
PM_{10}	N/A	N/A	1.85	1.85
SO_X	N/A	N/A	0.89	0.89
NH_3	N/A	N/A	4.24	4.24

b. Maximum Daily PE

Maximum daily emissions for NO_X and CO emissions occurs when each CTG undergoes one (1) hour operating in startup mode, one (1) hour operating in shutdown mode and twenty two (22) hours operating at full load. Maximum daily emissions for VOC, PM_{10}, SO_X, and NH_3 occur when each CTG operates twenty-four (24) hours at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit				
	Startup Emissions Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Daily PE (per CTG) (lb/day)
NO_X	4.17	1.50	2.80	67.3
CO	12.50	21.33	4.19	126.0
VOC	0.83	0.83	0.82	19.7
PM_{10}	N/A	N/A	1.85	44.4
SO_X	N/A	N/A	0.89	21.4
NH_3	N/A	N/A	4.24	101.8

c. ***Maximum Quarterly PE***

First and Second Quarters:

Maximum quarterly emissions for NO_X, CO and VOC emissions occurs when each CTG undergoes one 21.9 hours operating in startup mode, 21.9 hours operating in shutdown mode and 756.2 hours operating at full load. Maximum quarterly emissions for PM_{10}, SO_X, and NH_3 occur when each CTG operates 800 hours at full load. The results are summarized in the table below:

First and Second Quarter Potential to Emit				
	Startup Emissions Rate (lb/hr)	Shutdown Emissions Rate (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Quarterly PE (per CTG) (lb/qtr)
NO_X	4.17	1.50	2.80	2,242
CO	12.50	21.33	4.19	3,909
VOC	0.83	0.83	0.82	664
PM_{10}	N/A	N/A	1.85	1,480
SO_X	N/A	N/A	0.89	712
NH_3	N/A	N/A	4.24	3,392

Third Quarter:

Maximum quarterly emissions for NO_X, CO and VOC emissions occurs when each CTG undergoes one 38.325 hours operating in startup mode, 38.325 hours operating in shutdown mode and 1,323.35 hours operating at full load. Maximum quarterly emissions for PM_{10}, SO_X, and NH_3 occur when each CTG operates 1,400 hours at full load. The results are summarized in the table below:

Third Quarter Potential to Emit				
	Startup Emissions Rate (lb/hr)	Shutdown Emissions Rate (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Quarterly PE (per CTG) (lb/qtr)
NO_X	4.17	1.50	2.80	3,923
CO	12.50	21.33	4.19	6,841
VOC	0.83	0.83	0.82	1,162
PM_{10}	N/A	N/A	1.85	2,590
SO_X	N/A	N/A	0.89	1,246
NH_3	N/A	N/A	4.24	5,936

Fourth Quarter:

Maximum quarterly emissions for NO_X, CO and VOC emissions occurs when each CTG undergoes one 27.375 hours operating in startup mode, 27.375 hours operating in shutdown mode and 945.25 hours operating at full load. Maximum quarterly emissions for PM_{10}, SO_X, and NH_3 occur when each CTG operates 1,000 hours at full load. The results are summarized in the table below:

Fourth Quarter Potential to Emit				
	Startup Emissions Rate (lb/hr)	Shutdown Emissions Rate (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Quarterly PE (per CTG) (lb/qtr)
NO_X	4.17	1.50	2.80	2,802
CO	12.50	21.33	4.19	4,887
VOC	0.83	0.83	0.82	830
PM_{10}	N/A	N/A	1.85	1,850
SO_X	N/A	N/A	0.89	890
NH_3	N/A	N/A	4.24	4,240

d. Maximum Annual PE

The maximum annual PE is merely the sum of the maximum quarterly PE calculated in section VII.C.2.i.c of this document. The results are summarized in the table below:

Maximum Annual PE (per CTG)						
Quarter	NO_X (lb/qtr)	CO (lb/qtr)	VOC (lb/qtr)	PM_{10} (lb/qtr)	SO_X (lb/qtr)	NH_3 (lb/qtr)
1^{st} (lb/qtr)	2,242	3,909	664	1,480	712	3,392
2^{nd} (lb/qtr)	2,242	3,909	664	1,480	712	3,392
3^{rd} (lb/qtr)	3,923	6,841	1,162	2,590	1,246	5,936
4^{th} (lb/qtr)	2,802	4,887	830	1,850	890	4,240
Annual PE (lb/yr)	11,209	19,546	3,320	7,400	3,560	16,960

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

As discussed above, Starwood Power will be considered a part of the same stationary source as the existing Cal Peak Power – Panoche facility (C-3811) that is located right next to the proposed site. Therefore, this is an existing stationary source and the SSPE1 totals will be set equal to the emissions from facility C-3811. The SSPE1 values listed in the following table were taken from the application review performed under the most recent project for facility C-3811, 1041101. This facility does not have any banked ERC's.

Pre-project Stationary Source Potential to Emit [SSPE1]					
Permit Unit	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
C-3811-1 C-3811-2	20,000	33,555	3,995	10,112	4,432
Pre-project SSPE (SSPE1)	20,000	33,555	3,995	10,112	4,432

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2]					
Permit Unit	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
C-3811-1 C-3811-2	20,000	33,555	3,995	10,112	4,432
C-7286-1	11,209	19,546	3,320	7,400	3,560
C-7286-2	11,209	19,546	3,320	7,400	3,560
C-7286-3	11,209	19,546	3,320	7,400	3,560
C-7286-4	11,209	19,546	3,320	7,400	3,560
Post-project SSPE (SSPE2)	64,836	111,739	17,275	39,712	18,672

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	64,836	111,739	17,275	39,712	18,672
Major Source Threshold	50,000	200,000	50,000	140,000	140,000
Major Source?	Yes	No	No	No	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X emissions after this project. However, since these turbines are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

As discussed in Section VII.C.5 above, the facility is a Major Source for NO_X; however, the project by itself would need to be a significant increase in order to trigger a Major Modification. The emissions units within this project do not have a total potential to emit which is greater than Major Modification thresholds (see table below). Therefore, the project cannot be a significant increase and the project does not constitute a Major Modification.

Major Modification Thresholds			
Pollutant	Project PE (lb/year)	Threshold (lb/year)	Major Modification?
NO_x	44,836	50,000	No
VOC	13,280	80,000	No
PM_{10}	29,600	30,000	No
SO_X	14,240	50,000	No

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification. The four CTG's will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for the NO_X, CO and O_2 CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

- Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-1 is operating independently and while unit C-7286-2 is operating independently and while units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][(3)]

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-1 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][(3)]

(3) Similar conditions will appear on units C-7286-3 and '-4, with units '-3 and '-4 identified.

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081 and 40 CFR 60.4375(b)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

<u>C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:</u>

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

<u>Proposed Rule 1100 Conditions</u>:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, Starwood Power is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. Stationary Source Determination:

Pursuant to Section 3.37, a Stationary Source is defined as any building, structure, facility, or installation which emits or may emit any affected pollutant directly or as a fugitive emission. Building, structure, facility or installation includes all pollutant emitting activities including emissions units which:

- Are under the same or common ownership or operation, or which are owned or operated by entities which are under common control; and
- Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and
- Are located on one or more contiguous or adjacent properties; or
- Are located on one or more properties wholly within either the Western Kern County Oil Fields or the Central Kern County Oil Fields or Fresno County Oil Fields and are used for the production of light oil, heavy oil, or gas. Notwithstanding the provisions of this definition, light oil production, heavy oil production, and gas production shall constitute separate Stationary Sources

Cal Peak Power – Panoche, LLC (Facility C-3811) is an existing peaking power plant located at 43699 W. Panoche Road in Firebaugh, CA. This existing facility is located right next to the proposed site (see site layout in Attachment B). Pursuant to information provided by the applicant for this project, Starwood Energy Goup Global, LLC, owns the existing Cal Peak Power – Panoche facility and the proposed Starwood Power facility. In addition, both of these facilities are peaking power generating facilities that belong to the same two-digit standard industrial classification (SIC) code. Therefore, the emission units operated at these two sites meet the criteria specified above and will be considered as a part of the same Stationary Source for the purposes of this project, and all future projects. The following condition will be included on each permit to ensure continued compliance with the requirements of this rule:

- District facilities C-3811 and C-7286 are the same stationary source for District permitting purposes. [District Rule 2201]

B. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install four new combustion turbine generators with PE values greater than 2.0 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. Therefore, BACT is triggered for NO_X, VOC, PM_{10}, and SO_X emissions. However, since the SSPE2 for CO emissions is less than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document, BACT will not be required for CO emissions.

The PE of ammonia is greater than 2.0 pounds per day for each of the four CTG's. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

BACT Guideline 3.4.8, 4^{th} quarter 2006, applies to gas turbines rated at less than 50 MW, without heat recovery. Starwood Power is proposing to install four 30 MW simple cycle gas turbines without heat recovery equipment. Therefore, BACT Guideline 3.8.4 is applicable to each of the four CTG's and no further discussion is required (BACT Guideline 3.4.8 included in Attachment E).

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

Pursuant to the Top-Down BACT Analysis in Attachment F, BACT is satisfied with the following:

NO_X: 2.5 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with water injection, SCR with ammonia injection and natural gas fuel

VOC: 2.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown)

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC-regulated natural gas

The following conditions will ensure continued compliance with the BACT requirements of this rule:

- All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

- A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- The CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X and PM_{10} emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	64,836	111,739	17,725	39,712	18,672
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	No	Yes	No

2. Quantity of Offsets Required:

Per Sections 4.7.2 and 4.7.3, the quantity of offsets, in pounds per year, is calculated as follows for sources with an SSPE1 less than or equal to the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

<u>NO_X Offset Calculations:</u>

NO_X SSPE2 = 64,836 lb/year
NO_X offset threshold = 20,000 lb/year
ICCE = 0 lb/year

Offsets = [64,836 – 20,000] x DOR
= 44,836 lb/year ∗ DOR

Starwood Power will be limited to the quarterly emission rates calculated in Section VII.C.2.c above. Based on those NO_X emission values, the appropriate quarterly emissions to be offset without the distance offset ratio as follows:

Quantity of Offsets Required (without DOR)					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	8,968	8,968	15,692	11,208	44,836

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 44,836 lb-NO_X/year x 1.5
Offsets Required = 67,254 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	13,452	13,452	23,538	16,812	67,254

The applicant has stated that the facility plans to use ERC certificate S-2382-2 to offset the increases in NO_X emissions associated with this project. The above Certificate has available quarterly NO_X credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
ERC #S-2382-2	13,676	18,234	18,234	18,234	68,378

As shown above, Starwood Power does not have enough NO_X ERC's for the 3rd quarter to cover the amount required by this project. However, they have extra NO_X ERC's for the 1st, 2nd and 4th quarters. Per District Rule 2201, Section 4.13.8, emission reductions for NO_X and VOC emissions that occurred from April through November may be used to offset increases in NO_X and VOC emissions during any period of the year. Therefore, only the emission reductions from the 2nd quarter and the first two-thirds of the 4th quarter can be used during the 3rd quarter. The following table compares the available amount of credits on ERC certificate S-2382-2, the required amount of ERC's for this project and the remaining ERC's available from April through November:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
ERC #S-2382-2	13,676	18,234	18,234	18,234	68,378
Required ERC's	13,452	13,542	23,538	16,812	67,254
Difference: Quarterly	224	4,692	-5,304	1,422	1,034
Difference: Apr - Nov	0	4,692	-5,304	948	336

Therefore, as seen above, the facility has sufficient credits to fully offset the quarterly amount of NO_X emissions required for this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 39,712 lb/year
PM_{10} offset threshold = 29,200 lb/year
ICCE = 0 lb/year

Offsets = [39,712 – 29,200] x DOR
= 10,512 lb/year x DOR

Starwood Power will be limited to the quarterly emission rates calculated in Section VII.C.2.c above. The quarterly PM_{10} emission values are based on the following operating scenario: quarter 1 – 800 hours (20% of allowable annual operation); quarter 2 – 800 hours (20% of allowable annual operation); quarter 3 – 1,400 hours (35% of allowable annual operation); and quarter 4 – 1,000 hours (25% of allowable annual operation). Based on these operational percentages, the appropriate quarterly emissions to be offset without the distance offset ratio as follows:

Quantity of Offsets Required (without DOR)					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	2,102	2,103	3,679	2,628	10,512

Starwood Power has proposed to offset the required amount of PM_{10} emissions required by this project with SO_X emission reduction credits (ERC's). Pursuant to the SO_X for PM_{10} interpollutant offset analysis included in Attachment H, SO_X ERC's may be allowed to offset PM_{10} emission increase at a ratio of 1.867:1.

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

As a worst case, the District will assume that the SO_X ERC's that Starwood Power does obtain will have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio (DOR) of 1.5:1 is applicable.

Multiplying the interpollutant offset ratio discussed above (1.867:1) with the distance offset ratio (1.5:1), an overall offset ratio of 2.8:1 is required for utilizing SO_X ERC's for the required PM_{10} offsets. Therefore the amount of SO_X ERC's that need to be withdrawn for PM_{10} offsets for this project is as follows:

Offsets Required = 10,512 lb-PM_{10}/year x 2.8
Offsets Required = 29,434 lb-PM_{10}/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	5,886	5,888	10,301	7,359	29,434

The applicant has stated that the facility plans to use ERC certificate S-2459-5 (or a certificate split from that certificate) to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased 43.0 tons per year of the above certificate, which has available quarterly SO_X credits as follows:

Offset Proposal				
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)
ERC #S-2459-5 (available amount)	21,500	21,500	21,500	21,500
Total:	21,500	21,500	21,500	21,500

As seen above, the facility has sufficient credits to fully offset the quarterly amount of PM_{10} emissions required for this project. The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 8,968 lb; 2nd quarter – 8,968 lb; 3rd quarter – 15,692 lb; and 4th quarter - 11,208 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 2,102 lb; 2nd quarter – 2,103 lb; 3rd quarter – 3,679 lb; and 4th quarter – 2,628 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) S-2382-2 and S-2459-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

- Quarterly emissions from this CTG shall not exceed any of the following limits: NOx (as NO2) – Q1: 2,242 lb, Q2: 2,242 lb, Q3: 3,923 lb or Q4: 2,802 lb; and PM_{10} – Q1: 1,480 lb, Q2: 1,480 lb, Q3: 2,590 lb or Q4: 1,850 lb. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII above, Starwood Power is a new facility, but by itself, is not a Major Source (when not including emissions from Cal Peak Power, facility C-3811, which is considered a part of the same stationary source as the proposed facility). Therefore, public noticing is not required for this project for new Major Source purposes.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-7286-1-0	67.3	126.0	19.7	44.4	21.4	101.8
C-7286-2-0	67.3	126.0	19.7	44.4	21.4	101.8
C-7286-3-0	67.3	126.0	19.7	44.4	21.4	101.8
C-7286-4-0	67.3	126.0	19.7	44.4	21.4	101.8
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	No	**Yes**	No	No	No	**Yes**

According to the table above, permit units C-7286-1-0, '-2-0, '-3-0 and -4-0 will each have a Potential to Emit greater than 100 lb/day for CO and NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	20,000	64,836	20,000 lb/year	Yes
CO	33,555	111,739	200,000 lb/year	No
VOC	3,995	17,275	20,000 lb/year	No
PM_{10}	10,112	39,712	29,200 lb/year	Yes
SO_X	4,432	18,672	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	64,836	20,000	44,836	20,000 lb/year	Yes
CO	111,739	33,555	78,184	20,000 lb/year	Yes
VOC	17,275	3,995	13,280	20,000 lb/year	No
PM_{10}	39,712	10,112	29,600	20,000 lb/year	Yes
SO_X	18,672	4,432	14,240	20,000 lb/year	No

As demonstrated above, the SSIPE's for NO_X, CO and PM_{10} emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day limits and/or emission factors. The following conditions will ensure continued compliance with the DEL requirements of this rule:

- Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Combined emission rates from the CTG's operating under permit units C-7286-1 and C-7286-2 (or C-7286-3 and C-7286-4), except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 5.6 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 8.38 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 1.64 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 3.70 lb/hr; or SO_X (as SO_2) – 1.78 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

- During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

- The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

- Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

- Daily emissions from this CTG shall not exceed any of the following limits: NO_X (as NO_2) – 67.3 lb/day; CO – 126.0 lb/day; VOC – 19.7 lb/day; PM_{10} – 44.4 lb/day; or SO_X (as SO_2) – 21.4 lb/day. [District Rule 2201]

- Combined daily emissions from the CTG's operating under permit units C-7286-1 and C-7286-2 (or C-7286-3 and C-7286-4) shall not exceed any of the following limits: NO_X (as NO_2) – 134.6 lb/day; CO – 252.0 lb/day; VOC – 39.4 lb/day; PM_{10} – 88.8 lb/day; or SO_X (as SO_2) – 42.8 lb/day. [District Rule 2201]

- This CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 11,209 lb/year; CO – 19,546 lb/year; VOC – 3,320 lb/year; PM_{10} – 7,400 lb/year; or SO_X (as SO_2) – 3,560 lb/year. [District Rule 2201]

- Combined annual emissions from the CTG's operating under permit units C-7286-1 and C-7286-2 (or C-7286-3 and C-7286-4), calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 22,418 lb/year; CO – 39,092 lb/year; VOC – 6,640 lb/year; PM_{10} – 14,800 lb/year; or SO_X (as SO_2) – 7,120 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this project is not considered a new Major Source or a Major Modification. Therefore, the requirements of this section are not applicable and no further discussion is required.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.021[(4)]	0.65[(5)]	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

District Rule 4703, Section 6.3.1 states that the owner or operator of any stationary gas turbine shall perform source testing for NO_X and CO emissions on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be required within 120 days of initial operation and at least once every 12 months thereafter.

(4) Worst case annual PM_{10} contribution is when both turbines within each SwiftPac are operating simultaneously (four turbines total).
(5) Worst case 24 hour PM_{10} contribution is when one turbine within each SwiftPac is operating simultaneously (two turbines total).

As discussed above, Starwood Power will consist of two Pratt & Whitney, model FT8-3 SwiftPac, gas turbine generator units. Each SwiftPac will consist of two natural gas fired turbines that drive opposite ends of a single electric generator. Each gas turbine will have the ability to operate independently of the other gas turbine generator driving the opposite end of the single electric generator. The exhaust paths of the two turbines within each SwiftPac merge into one exhaust path before entering the SCR system and oxidation catalyst.

Typically, each turbine is required to source test to demonstrate compliance with all of the emission limits. Since Starwood Power will be set up where two turbines exhaust through a common stack, the only way to source test each turbine individually would be to shut down the other turbine down in which the common stack is shared with. Depending on the demand for power at any given time of the year, it may not always be feasible for Starwood Power to shutdown one of the turbines at this facility. Therefore, the District will allow Starwood Power to perform source testing while one, or both, of the turbines within a SwiftPac are operating. However, initial source testing will be required on each turbine individually and when both turbines are operating simultaneously to ensure that each turbine is in compliance with all applicable limits.

Therefore, the following source testing requirements will ensure continued compliance with the requirements of this rule:

- Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-1 is operating independently and while unit C-7286-2 is operating independently and while units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][6]

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-1 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][6]

In addition, source testing of NO_X and CO startup and shutdown emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then source testing to measure startup NO_X and CO mass emission rates shall be conducted at least once every 12 months. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEM's accurately measure startup emissions.

(6) Similar conditions will appear on units C-7286-3 and '-4, with units '-3 and '-4 identified.

- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

Two CTG's exhaust stacks will merge into one common exhaust stack prior to entering the SCR system and oxidation catalyst. The common exhaust stack will be equipped with CEMs for NO_X, CO, and O_2. The CEM's will take readings while one, or both, of the CTG's are operating. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

2. Monitoring

<u>C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:</u>

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Starwood Power will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

3. Recordkeeping

C-37286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

4. Reporting

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X after this project.

- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.

- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.

- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is required to obtain a PSD permit from the EPA.

As discussed above, this new source is considered as a part of the same stationary source as the existing Cal Peak Power-Panoche (Facility ID C-3811) power generating facility located next to the proposed site. Cal Peak Power operates two 24.7 MW simple cycle turbines. This existing facility is subject to the requirements of this rule in accordance with Section 2.5, acid rain and received their initial Title V permit on March 22, 2004.

Since these two facilities are considered a part of the same stationary source, the turbines proposed by Starwood Power, should be included under the same Title V permit as Cal Peak Power – Panoche. Starwood Power has indicated that Cal Peak Power – Panoche will not have any responsibility over the operating permits for the proposed turbines. Therefore, Starwood Power has asked that the proposed turbines not be included under the same facility ID number and Title V operating permit as the existing Cal Peak Power facility. Due to this request, Starwood Power will be required to obtain their own Title V permit that is totally independent of the existing Title V permit for Cal Peak Power – Panoche.

Pursuant to Rule 2520 section 5.3, new sources must submit an initial Title V permit application within 12 months of commencing operations. Since Starwood Power is a new source and the District will be issuing them their own Title V permit, they will be required to submit an initial Title V permit application within 12 months of commencing operation. No action is required at this time. The following condition will ensure that Starwood Power submits an application to comply with the requirements of this rule within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in June of 2004.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will ensure that Starwood Power submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[(7)]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). Any pollutant that may be emitted from the project and is on the federal New Source Review List and the federal Clean Air Act list has been evaluated.

The applicant has supplied the following data.

[(7)] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

Hazardous Air Pollutant Emissions
Starwood Power – Pratt & Whitney FT8-3 Turbines

Hazardous Air Pollutant	Emission Factor (lb/MMSCF)[1]	Maximum Hourly Emissions per Turbine (lb/hr)[2]	Maximum Annual Emissions per Turbine (lb/yr)[3]	Maximum Annual Emissions, Four Turbines (lb/yr)
Acetaldehyde	3.70E-02	1.12E-02	45	180
Acrolein	9.00E-03	2.74E-03	11	44
Benzene	1.13E-02	3.43E-03	14	56
Ethylbenzene	1.32E-02	4.01E-03	16	64
Formaldehyde	9.4E-02	2.86E-02	114	456
Hexane	1.75	5.32E-01	2,130	8,520
Propylene	1.0522	3.20E-01	1,280	5,120
Toluene	7.26E-02	2.21E-02	88	352
Xylene	2.89E-02	8.78E-03	35	140
Naphthalene	8.00E-04	2.43E-04	1	4
Polycyclic aromatic hydrocarbons (PAH's)	2.00E-04	6.08E-05	2.43E-01	1
Total			**3,734.24**	**14,937**

1 From Ventura County Air Pollution Control District AB2588 Emission Factors for Internal Combustion Turbines, 1995.
2 Based on a maximum hourly turbine heat input of 311.2 MMBtu/hr and fuel HHV of 1,024 Btu/scf. (0.304 MMscf/hr)
3 Based on a maximum annual turbine heat input of 1,244,800 MMBtu/year and fuel HHV of 1,024 Btu/scf. (1,216 MMscf/yr)

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, Starwood Power will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

<u>40 CFR 60 – Subpart GG</u>

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Starwood Power has indicated that the installation and construction of the proposed turbines will be completed in 2008. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Starwood Power has indicated that the installation and construction of the proposed turbines will be completed in 2008. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 311 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 50 MMBtu/hr but less than or equal to 850 MMBtu/hr shall meet a NO_X emissions limit of 25 ppmvd @ 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh).

Starwood Power is proposing a NO_X emission concentration limit of 2.5 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Starwood Power is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Paragraph (b) states that alternatively, an operator may use continuous emission monitoring, as follows:

(1) Install, certify, maintain and operate a continuous emissions monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
(2) For units complying with the output-based standard, install, calibrate, maintain and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
(3) For units complying with the output based standard, install, calibrate, maintain and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

Starwood Power operates each of these turbines with water injection. They are proposing to install, certify, maintain and operate a CEMS consisting of a NO_X monitor and an O_2 monitor to determine hourly NO_X emission rate in ppm. They are not proposing to comply with the output-based NO_X emission standards listed in Table 1. Therefore, the proposed CEMS satisfies the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

This section specifies the requirements for units not equipped with water or steam injection. As discussed above, Starwood Power is proposing to use water injection to reduce NO_X emissions in each of these turbines. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Starwood Power will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Starwood Power is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Starwood Power is proposing to monitor the NO_X emissions rates from these turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets fourth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Starwood Power is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Starwood Power is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Starwood Power has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Starwood Power is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Starwood Power is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for these turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Starwood Power is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document document proper operation of the NO_X emission controls. Starwood Power is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Starwood Power will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Starwood Power is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Starwood Power will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-1 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][8]

[8] Similar conditions will appear on units C-7286-3 and '-4, with units '-3 and '-4 identified.

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Starwood Power has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Starwood Power is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Starwood Power is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Starwood Power is not proposing to measure the SO_2 in the exhaust stream of these turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Pursuant to Section 2.0, "*All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;*" therefore, the requirements of this rule applies to the Starwood Power. However, there are no applicable requirements for a non-major HAPs source. As discussed above, Starwood Power is not a major HAP source; therefore, no actions are necessary to show compliance with this rule.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

The CTG's lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement and the exhaust stack emissions will be limited by permit condition to no greater than 20% opacity except for three minutes in any hour. Therefore compliance is expected.

Proposed Rule 4101 Conditions:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

Rule 4102 *Nuisance*

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, compliance with this rule is expected.

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-7286-1-0 (Turbine #1) C-7286-2-0 (Turbine #2) C-7286-3-0 (Turbine #3) C-7286-4-0 (Turbine #4)	0.0	0.0	0.404	No

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:

$$PM\ Conc.\ (gr/scf) = \frac{(PM\ emission\ rate) \times (7000\ gr/lb)}{(Air\ flow\ rate) \times (60\ min/hr)}$$

PM_{10} emission rate = 1.85 lb/hr. Assuming 100% of PM is PM_{10}
H_2O = 16.73%
Exhaust Gas Flow, scfm (wet) = 408,145
Exhaust Gas Flow, dscfm = 408,145 ∗ [(100 – 16.73)/100] = 339,862

PM Conc. (gr/scf)=[(1.85 lb/hr) ∗ (7,000 gr/lb)] ÷ [(339,862 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.00064 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

Proposed Rule 4201 Condition:

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the four CTG's and no further discussion is required.

Rule 4301 ***Fuel Burning Equipment***

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4703 ***Stationary Gas Turbines***

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install four 30 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR), based on the following equation:

$$NO_X\ (\text{ppmv} @ 15\%\ O_2) = 9 \times \left(\frac{\text{EFF}}{25}\right)$$

Where EFF is the higher of EFF_1 or EFF_2 where:

$$EFF_1 = \frac{3{,}412\ \frac{\text{Btu}}{\text{kW}-\text{hr}}}{\text{Actual Heat Rate @ HHV}\ (\frac{\text{Btu}}{\text{kW}-\text{hr}})} \times 100\text{, and } EFF_2 = EFF_{MFR}\frac{\text{LHV}}{\text{HHV}}$$

EFF_2 = EFF_{mfr} * (LHV/HHV)

Calculated data indicates that the Actual Heat Rate @ HHV is 10,165 Btu/KW-hr (worst case based on an ambient inlet temperature of 63.3 °F). Therefore:

$$EFF_1 = \frac{3{,}412\ \frac{\text{Btu}}{\text{kW}-\text{hr}}}{10{,}165\ \frac{\text{Btu}}{\text{kW}-\text{hr}}} \times 100 = 33.57\%$$

$$NO_X \text{ limit utilizing } EFF_1 = 9 \times \left(\frac{33.57}{25}\right) = 12.1 \text{ ppmvd @ } 15\% \ O_2$$

EFF_2 calculations are not necessary since Rule 4703 emission limits will be no lower than 9 ppmv NO_X and the proposed turbines will be limited to a maximum of 2.0 ppmv NO_X @ 15% O_2 (based on a 1-hour average), therefore compliance is expected.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from simple cycle, stationary gas turbine systems rated at greater than 10 MW and allowed to operate more than 876 hours per year to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.5 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines must be less than 200 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Starwood Power is proposing a CO emission concentration limit of 6 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

<u>Section 5.3 – Startup and Shutdown Requirements:</u>

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Starwood Power is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than two hours. The SCR system and oxidation catalyst will be in operation during startup and shutdown in order to minimize emissions insofar as technologically feasible during startups and shutdowns. Therefore, the proposed turbines will be operating in compliance with the startup and shutdown requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up, emissions from this unit not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

- During shutdown, emissions from this unit not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

<u>Section 6.2 - Monitoring and Record Keeping:</u>

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines will not be installed until 2008. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Starwood Power will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Starwood Power will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Starwood Power will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr, lb/quarter and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Starwood Power will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Starwood Power are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-1 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)][9]

[9] Similar conditions will appear on units C-7286-3 and '-4, with units '-3 and '-4 identified.

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, each of the proposed turbines will be allowed to operate up to 4,000 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. Starwood Power is not proposing to operate any of these turbines with auxiliary burners. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

<u>Conclusion:</u>

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

<u>C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0:</u>

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_x: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.
- Weight of SO_x as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00285\ lb}{MMBtu} \times \frac{1\ (lb - mol)}{64\ lb} = 0.000045\ (lb - mol)$
- $R = \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

District Rule 8011 General Requirements
District Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities
District Rule 8031 Bulk Materials
District Rule 8041 Carryout And Trackout
District Rule 8051 Open Areas
District Rule 8061 Paved And Unpaved Roads
District Rule 8071 Unpaved Vehicle/Equipment Traffic Areas
District Rule 8081 Agricultural Sources

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

It has been determined that the project has the potential to adversely affect the environment and therefore subject to requirements of the California Environmental Quality Act (CEQA). The California Energy Commission (CEC) is the lead agency for CEQA. Upon satisfaction of the CEQA requirements for this project, the CEC will issue a Certification to Starwood Power approving construction and operation of the power plant. The District's FDOC conditions will be incorporated into the CEC's Certification for this power plant project. Therefore, CEQA requirements will be satisfied prior to approval of construction.

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Preliminary Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-7286-1-0	3020-08A-F	30,000 kW	$7,004.00
C-7286-2-0	3020-08A-F	30,000 kW	$7,004.00
C-7286-3-0	3020-08A-F	30,000 kW	$7,004.00
C-7286-4-0	3020-08A-F	30,000 kW	$7,004.00

ATTACHMENT A

PDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-7286-1-0:

30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-2)

1. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 8,968 lb; 2nd quarter – 8,968 lb; 3rd quarter – 15,692 lb; and 4th quarter - 11,208 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

2. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 2,102 lb; 2nd quarter – 2,103 lb; 3rd quarter – 3,679 lb; and 4th quarter – 2,628 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. ERC certificate numbers (or any splits from these certificates) S-2382-2 and S-2459-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

4. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

5. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

6. District facilities C-3811 and C-7286 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of the Starwood Power-Midway, LLC (Starwood Power) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #7 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #19 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the Starwood Power construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the steady-state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in condition #28. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 41.65 lb/hr; CO – 19.9 lb/hr; VOC (as methane) – 0.80 lb/hr; PM10 – 1.85 lb/hr; or SOx (as SO2) – 0.89 lb/hr. [District Rule 2201]

15. During the commissioning period, the permittee shall demonstrate compliance with the NO_X and CO limits specified in condition #14 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in conditions #52 and 53. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

16. The continuous monitors specified in this permit shall be installed, calibrated, and operational prior to the first firing of this unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emission concentrations. [District Rule 2201]

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 100 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 100 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NOx, CO, VOC, PM10, and SOx that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. [District Rule 2201]

19. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

22. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

23. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

24. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

25. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

26. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

27. This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

29. Combined emission rates from the CTG's operating under permit units C-7286-1 and C-7286-2, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 5.6 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 8.38 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 1.64 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 3.70 lb/hr; or SO_X (as SO_2) – 1.78 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

31. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

32. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shut down time shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 67.3 lb/day; CO – 126.0 lb/day; VOC – 19.7 lb/day; PM_{10} – 44.4 lb/day; or SO_X (as SO_2) – 21.4 lb/day. [District Rule 2201]

37. Combined daily emissions from the CTG's operating under permit units C-7286-1 and C-7286-2 shall not exceed any of the following limits: NO_X (as NO_2) – 134.6 lb/day; CO – 252.0 lb/day; VOC – 39.4 lb/day; PM_{10} – 88.8 lb/day; or SO_X (as SO_2) – 42.8 lb/day. [District Rule 2201]

38. Quarterly emissions from this CTG shall not exceed any of the following limits: NOx (as NO2) – Q1: 2,242 lb, Q2: 2,242 lb, Q3: 3,923 lb or Q4: 2,802 lb; and PM_{10} – Q1: 1,480 lb, Q2: 1,480 lb, Q3: 2,590 lb or Q4: 1,850 lb. [District Rule 2201]

39. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 11,209 lb/year; CO – 19,546 lb/year; VOC – 3,320 lb/year; PM_{10} – 7,400 lb/year; or SO_X (as SO_2) – 3,560 lb/year. [District Rule 2201]

40. Combined annual emissions from the CTG's operating under permit units C-7286-1 and C-7286-2, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 22,416 lb/year; CO – 39,096 lb/year; VOC – 6,400 lb/year; PM_{10} – 14,800 lb/year; or SO_X (as SO_2) – 7,120 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

44. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

45. Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-1 is operating independently and while unit C-7286-2 is operating independently and while units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-1 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

48. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081 and 40 CFR 60.4375(b)]

52. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NO_X, CO and O_2 CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr, lb/qtr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rules 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7286-2-0:
30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-1)

1. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 8,968 lb; 2nd quarter – 8,968 lb; 3rd quarter – 15,692 lb; and 4th quarter - 11,208 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

2. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 2,102 lb; 2nd quarter – 2,103 lb; 3rd quarter – 3,679 lb; and 4th quarter – 2,628 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. ERC certificate numbers (or any splits from these certificates) S-2382-2 and S-2459-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

4. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

5. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

6. District facilities C-3811 and C-7286 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of the Starwood Power-Midway, LLC (Starwood Power) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #7 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #19 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the Starwood Power construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the steady-state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in condition #28. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 41.65 lb/hr; CO – 19.9 lb/hr; VOC (as methane) – 0.80 lb/hr; PM10 – 1.85 lb/hr; or SOx (as SO2) – 0.89 lb/hr. [District Rule 2201]

15. During the commissioning period, the permittee shall demonstrate compliance with the NO_X and CO limits specified in condition #14 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in conditions #52 and 53. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

16. The continuous monitors specified in this permit shall be installed, calibrated, and operational prior to the first firing of this unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emission concentrations. [District Rule 2201]

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 100 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 100 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NOx, CO, VOC, PM10, and SOx that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. [District Rule 2201]

19. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

22. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

23. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

24. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

25. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

26. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

27. This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

29. Combined emission rates from the CTG's operating under permit units C-7286-1 and C-7286-2, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 5.6 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 8.38 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 1.64 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 3.70 lb/hr; or SO_X (as SO_2) – 1.78 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

31. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

32. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shut down time shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 67.3 lb/day; CO – 126.0 lb/day; VOC – 19.7 lb/day; PM_{10} – 44.4 lb/day; or SO_X (as SO_2) – 21.4 lb/day. [District Rule 2201]

37. Combined daily emissions from the CTG's operating under permit units C-7286-1 and C-7286-2 shall not exceed any of the following limits: NO_X (as NO_2) – 134.6 lb/day; CO – 252.0 lb/day; VOC – 39.4 lb/day; PM_{10} – 88.8 lb/day; or SO_X (as SO_2) – 42.8 lb/day. [District Rule 2201]

38. Quarterly emissions from this CTG shall not exceed any of the following limits: NOx (as NO2) – Q1: 2,242 lb, Q2: 2,242 lb, Q3: 3,923 lb or Q4: 2,802 lb; and PM_{10} – Q1: 1,480 lb, Q2: 1,480 lb, Q3: 2,590 lb or Q4: 1,850 lb. [District Rule 2201]

39. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 11,209 lb/year; CO – 19,546 lb/year; VOC – 3,320 lb/year; PM_{10} – 7,400 lb/year; or SO_X (as SO_2) – 3,560 lb/year. [District Rule 2201]

40. Combined annual emissions from the CTG's operating under permit units C-7286-1 and C-7286-2, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 22,416 lb/year; CO – 39,096 lb/year; VOC – 6,400 lb/year; PM_{10} – 14,800 lb/year; or SO_X (as SO_2) – 7,120 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

44. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

45. Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-1 is operating independently and while unit C-7286-2 is operating independently and while units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-2 is operating independently or when units C-7286-1 and C-7286-2 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

48. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081 and 40 CFR 60.4375(b)]

52. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NO_X, CO and O_2 CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr, lb/qtr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rules 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7286-3-0:

30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-4)

1. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 8,968 lb; 2nd quarter – 8,968 lb; 3rd quarter – 15,692 lb; and 4th quarter - 11,208 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

2. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 2,102 lb; 2nd quarter – 2,103 lb; 3rd quarter – 3,679 lb; and 4th quarter – 2,628 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. ERC certificate numbers (or any splits from these certificates) S-2382-2 and S-2459-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

4. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

5. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

6. District facilities C-3811 and C-7286 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of the Starwood Power-Midway, LLC (Starwood Power) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #7 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #19 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the Starwood Power construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the steady-state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in condition #28. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 41.65 lb/hr; CO – 19.9 lb/hr; VOC (as methane) – 0.80 lb/hr; PM10 – 1.85 lb/hr; or SOx (as SO2) – 0.89 lb/hr. [District Rule 2201]

15. During the commissioning period, the permittee shall demonstrate compliance with the NO_X and CO limits specified in condition #14 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in conditions #52 and 53. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

16. The continuous monitors specified in this permit shall be installed, calibrated, and operational prior to the first firing of this unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emission concentrations. [District Rule 2201]

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 100 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 100 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NOx, CO, VOC, PM10, and SOx that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. [District Rule 2201]

19. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

22. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

23. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

24. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

25. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

26. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

27. This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

29. Combined emission rates from the CTG's operating under permit units C-7286-3 and C-7286-4, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 5.6 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 8.38 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 1.64 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 3.70 lb/hr; or SO_X (as SO_2) – 1.78 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

31. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

32. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shut down time shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 67.3 lb/day; CO – 126.0 lb/day; VOC – 19.7 lb/day; PM_{10} – 44.4 lb/day; or SO_X (as SO_2) – 21.4 lb/day. [District Rule 2201]

37. Combined daily emissions from the CTG's operating under permit units C-7286-3 and C-7286-4 shall not exceed any of the following limits: NO_X (as NO_2) – 134.6 lb/day; CO – 252.0 lb/day; VOC – 39.4 lb/day; PM_{10} – 88.8 lb/day; or SO_X (as SO_2) – 42.8 lb/day. [District Rule 2201]

38. Quarterly emissions from this CTG shall not exceed any of the following limits: NOx (as NO2) – Q1: 2,242 lb, Q2: 2,242 lb, Q3: 3,923 lb or Q4: 2,802 lb; and PM_{10} – Q1: 1,480 lb, Q2: 1,480 lb, Q3: 2,590 lb or Q4: 1,850 lb. [District Rule 2201]

39. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 11,209 lb/year; CO – 19,546 lb/year; VOC – 3,320 lb/year; PM_{10} – 7,400 lb/year; or SO_X (as SO_2) – 3,560 lb/year. [District Rule 2201]

40. Combined annual emissions from the CTG's operating under permit units C-7286-3 and C-7286-4, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 22,416 lb/year; CO – 39,096 lb/year; VOC – 6,400 lb/year; PM_{10} – 14,800 lb/year; or SO_X (as SO_2) – 7,120 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

44. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

45. Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-3 is operating independently and while unit C-7286-4 is operating independently and while units C-7286-3 and C-7286-4 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-3 is operating independently or when units C-7286-3 and C-7286-4 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

48. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081 and 40 CFR 60.4375(b)]

52. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NO_X, CO and O_2 CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr, lb/qtr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rules 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7286-4-0:
30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-3)

1. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 8,968 lb; 2nd quarter – 8,968 lb; 3rd quarter – 15,692 lb; and 4th quarter - 11,208 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

2. Prior to initial operation of C-7286-1-0, C-7286-2-0, C-7286-3-0 or C-7286-4-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 2,102 lb; 2nd quarter – 2,103 lb; 3rd quarter – 3,679 lb; and 4th quarter – 2,628 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. ERC certificate numbers (or any splits from these certificates) S-2382-2 and S-2459-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

4. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

5. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

6. District facilities C-3811 and C-7286 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of the Starwood Power-Midway, LLC (Starwood Power) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #7 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #19 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the Starwood Power construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the steady-state operation of the SCR system and the oxidation catalyst, NOx and CO emissions from this unit shall comply with the limits specified in condition #28. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 41.65 lb/hr; CO – 19.9 lb/hr; VOC (as methane) – 0.80 lb/hr; PM10 – 1.85 lb/hr; or SOx (as SO2) – 0.89 lb/hr. [District Rule 2201]

15. During the commissioning period, the permittee shall demonstrate compliance with the NO_X and CO limits specified in condition #14 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in conditions #52 and 53. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

16. The continuous monitors specified in this permit shall be installed, calibrated, and operational prior to the first firing of this unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emission concentrations. [District Rule 2201]

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 100 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 100 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NOx, CO, VOC, PM10, and SOx that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. [District Rule 2201]

19. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

22. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

23. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

24. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

25. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

26. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

27. This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. Emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 2.8 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 4.19 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 0.82 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

29. Combined emission rates from the CTG's operating under permit units C-7286-3 and C-7286-4, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 5.6 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 8.38 lb/hr and 6.0 ppmvd @ 15% O_2; VOC (as methane) – 1.64 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 3.70 lb/hr; or SO_X (as SO_2) – 1.78 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

31. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 4.17 lb/hr; CO – 12.5 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

32. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 1.50 lb/hr; CO – 21.33 lb/hr; VOC (as methane) – 0.83 lb/hr; PM_{10} – 1.85 lb/hr; or SO_X (as SO_2) – 0.89 lb/hr, based on three hour averages. [District Rules 2201 and 4703]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shut down time shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 67.3 lb/day; CO – 126.0 lb/day; VOC – 19.7 lb/day; PM_{10} – 44.4 lb/day; or SO_X (as SO_2) – 21.4 lb/day. [District Rule 2201]

37. Combined daily emissions from the CTG's operating under permit units C-7286-3 and C-7286-4 shall not exceed any of the following limits: NO_X (as NO_2) – 134.6 lb/day; CO – 252.0 lb/day; VOC – 39.4 lb/day; PM_{10} – 88.8 lb/day; or SO_X (as SO_2) – 42.8 lb/day. [District Rule 2201]

38. Quarterly emissions from this CTG shall not exceed any of the following limits: NOx (as NO2) – Q1: 2,242 lb, Q2: 2,242 lb, Q3: 3,923 lb or Q4: 2,802 lb; and PM_{10} – Q1: 1,480 lb, Q2: 1,480 lb, Q3: 2,590 lb or Q4: 1,850 lb. [District Rule 2201]

39. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 11,209 lb/year; CO – 19,546 lb/year; VOC – 3,320 lb/year; PM_{10} – 7,400 lb/year; or SO_X (as SO_2) – 3,560 lb/year. [District Rule 2201]

40. Combined annual emissions from the CTG's operating under permit units C-7286-3 and C-7286-4, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 22,416 lb/year; CO – 39,096 lb/year; VOC – 6,400 lb/year; PM_{10} – 14,800 lb/year; or SO_X (as SO_2) – 7,120 lb/year. [District Rule 2201]

41. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

42. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

43. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

44. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7286-1, C-7286-2, C-7286-3, or C-7286-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

45. Initial source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2) NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 120 days after initial operation. Initial source testing shall be conducted while unit C-7286-3 is operating independently and while unit C-7286-4 is operating independently and while units C-7286-3 and C-7286-4 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. Source testing may be conducted while unit C-7286-4 is operating independently or when units C-7286-3 and C-7286-4 are operating simultaneously. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

48. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5/202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081 and 40 CFR 60.4375(b)]

52. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NO_X, CO and O_2 CEMS as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr, lb/qtr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rules 8011 and 8071]

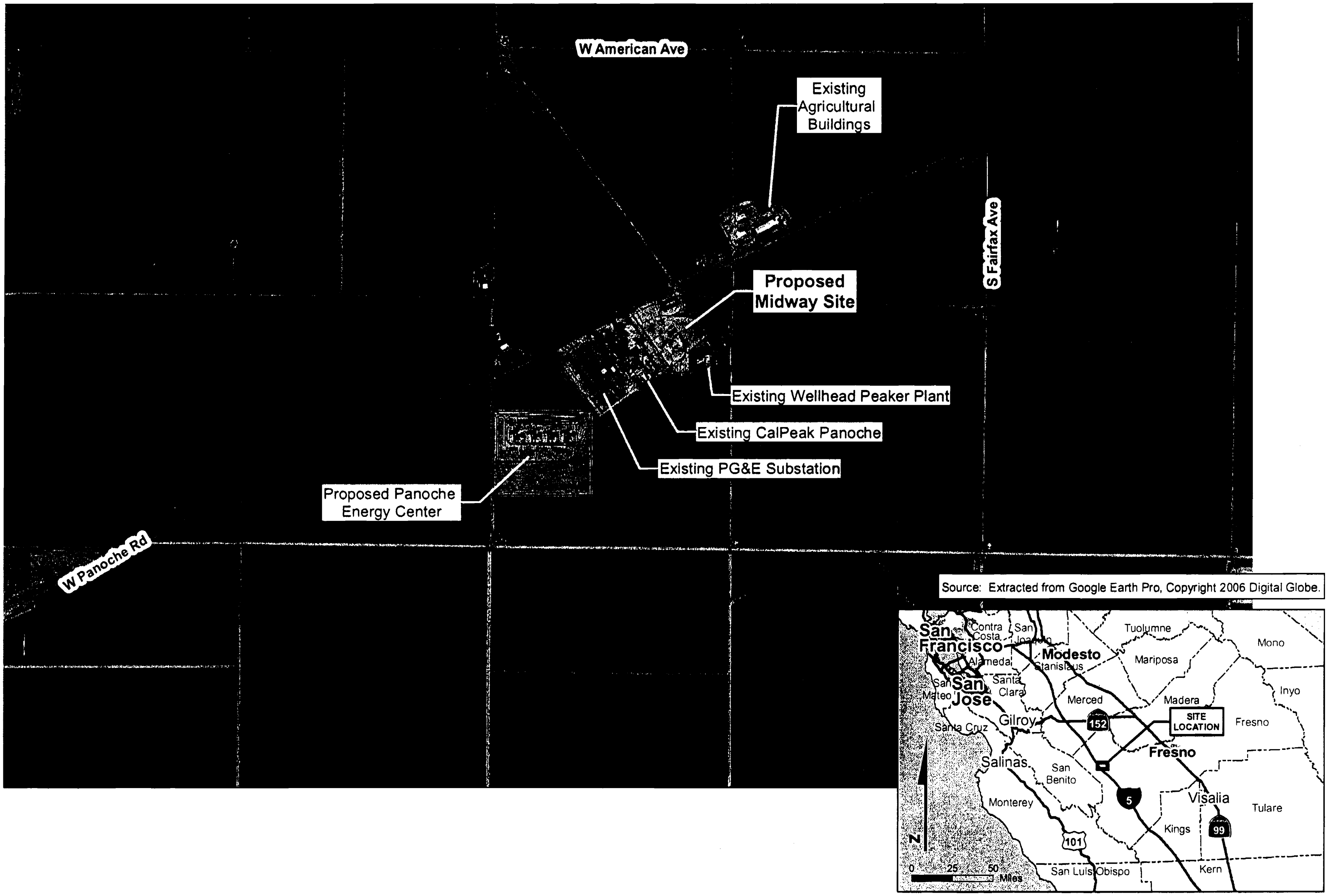
78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

ATTACHMENT B

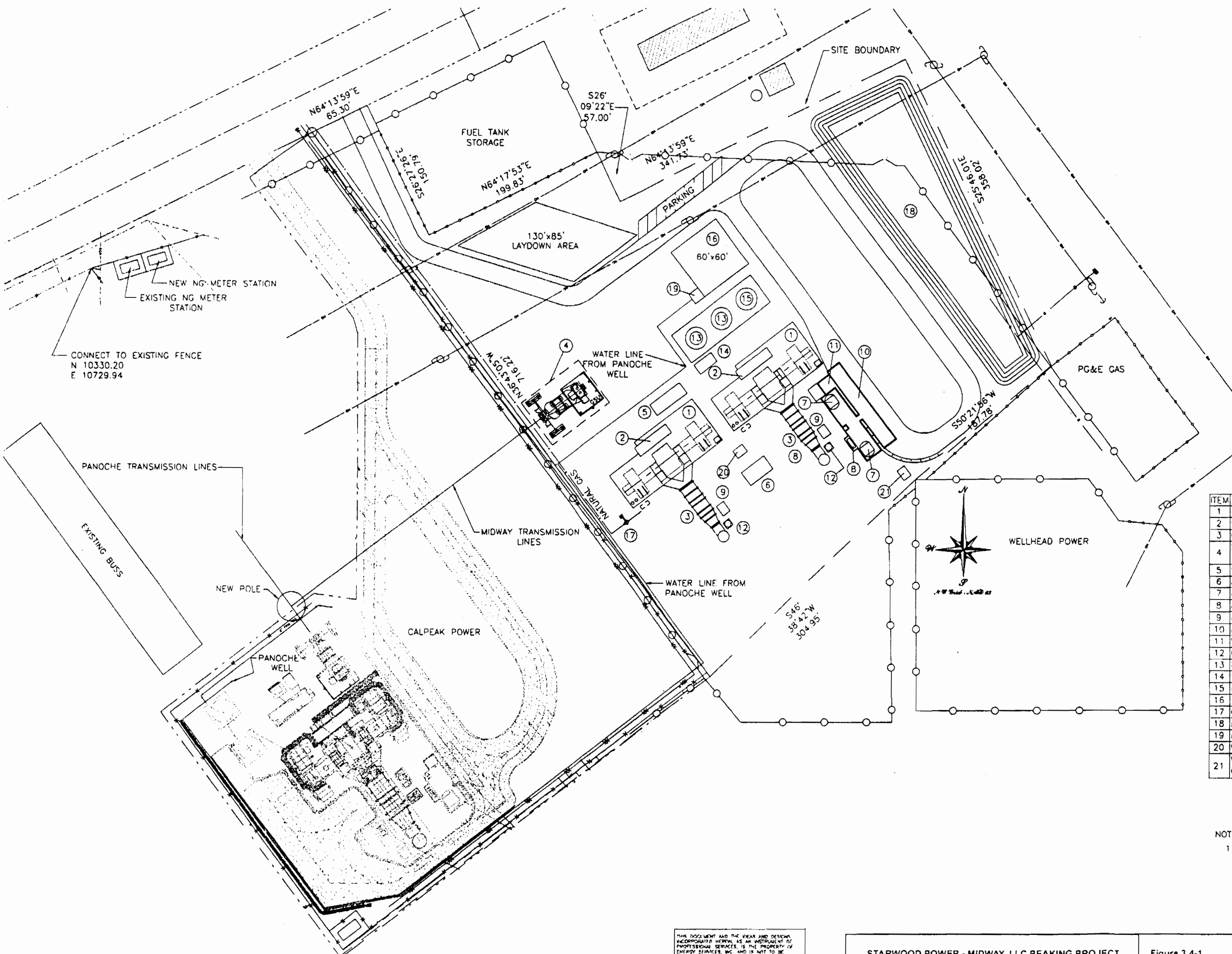
Project Location and Site Plan



Source: Extracted from Google Earth Pro, Copyright 2006 Digital Globe.

STARWOOD POWER - MIDWAY, LLC PEAKING PROJECT	Figure 1.2-1	AERIAL OF IMMEDIATE PROJECT VICINITY	2006

REV	DATE	DESCRIPTION	BY	APP
	22AUG06	INITIAL ISSUE	RAR	DAT



ITEM	DESCRIPTION	QTY
1	FT8-3 GAS TURBINE GENERATOR UNIT	2
2	PRIMARY CONTROL ENCLOSURE	2
3	CO/SCR CATALYST	2
4	SWITCH YARD/ MAIN STEP-UP TRANSFORMER/ DEAD END STRUCTURE (13.8x115 kV)	1
5	SECONDARY CONTROL ENCLOSURE	1
6	AIR COMPRESSOR/DRYER SKIDS	2
7	AQUEOUS AMMONIA TANK & CONTAINMENT AREA	1
8	AQUEOUS AMMONIA FORWARDING PUMP SKID	1
9	AQUEOUS AMMONGA INJECTION CONTROL SKID	2
10	AQUEOUS AMMONIA UNLOADING AREA	1
11	WASH DOWN DRAIN TANK AREA	1
12	CEMS ENCLOSURE	2
13	DEMINERALIZED WATER TANK (75,000 GALLON)	2
14	DEMINERALIZED WATER PUMP SKID	1
15	RAW WATER TANK (75,000 GALLON)	1
16	DI TRAILER PAD	1
17	GAS FUEL SCRUBBER	1
18	RO/EVAPORATION POND	1
19	RO UNIT	1
20	WASTE WATER SYSTEM COLLECTION SUMP	1
21	WASTE WATER SYSTEM ABOVE GROUND STORAGE TANK (4,700 GALLONS)	1

NOTES:

1. TANK DIMENSIONS= 23' DIAMETER x 24' HIGH

STARWOOD POWER - MIDWAY, LLC PEAKING PROJECT

Figure 3.4-1 PRELIMINARY PLAN

2006

ATTACHMENT C

CTG Commissioning Period Emissions Data

Commissioning Emissions

	Hours	Total Pounds Emitted		
	Hours	NO_x	CO	VOC
Controlled Break-in	5	47.79	12.09	0.41
Overspeed Test	1	9.56	2.42	0.08
Brush Generator Test	17	322.91	142.08	6.74
Water Injection Tuning	12.5	374.08	209.53	8.72
Fogger Commissioning	4	166.61	52.91	2.66
Catalyst Loading	4	166.61	52.91	2.66
SCR Commissioning	4	88.94	31.61	2.66
Full Load Testing	7.75	19.68	22.54	5.05
Emission Compliance	12	33.79	30.89	7.99
Startups/Shutdowns		44.37	31.16	1.44
Total Commissioning Hours	67.25	1274.34	588.14	38.41
		Maximum Emission Rates lb/hr		
		NO_x	CO	VOC
Controlled Break-in		9.56	2.42	0.08
Overspeed Test		9.56	2.42	0.08
Brush Generator Test		18.99	8.36	0.40
Water Injection Tuning		29.93	16.76	0.70
Fogger Commissioning		41.65	13.23	0.67
Catalyst Loading		41.65	13.23	0.67
SCR Commissioning		22.24	7.90	0.67
Full Load Testing		2.54	2.91	0.65
Emission Compliance		2.82	2.57	0.67

Worst-Case 1-Hour Emissions per Turbine

Worst-Case 1-Hour Emissions are equal to the commissioning emission rates, except for SO_2 and PM_{10} which have worst-case emissions during startup.

Emissions per turbine	lb/hr		g/s
NO_2	41.65		5.25
CO	19.90		2.51
VOC	0.70		0.09
SO_2	0.44		0.05
PM_{10}	1.85		0.23

The highest 1-hour commissioning emission rate occurs during a subset of the water injection tuning test.

Worst-Case 3 Hour Emission Rate per Turbine

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.

Worst-case 3-Hour Scenario are equal to 3 hours at normal rate.

Emissions per turbine	Worst-case Total	Startup /Warmup	Shutdown	Normal Operations	Worst-case Total	Startup /Warmup	Shutdown		Normal Operations	Worst-case Total
	lb/hr				Total lbs					g/s
Total Hours of Operation	3.0			3.00					3.000	
SO_2	0.44			0.44	1.31				1.31	0.05

Worst-Case 8-Hour Emission Rates

Only CO is considered for an average 8-hour Ambient Air Quality Standard.

Worst-case 8-Hour Scenario includes 8 hours of commissioning. Only one turbine will be undergoing commissioning at any one time.

Emissions per turbine	Worst-case Total	Startup /Warmup	Shutdown	Commissioning	Normal Operations	Worst-case Total	Startup /Warmup		Shutdown	Commissioning	Normal Operations	Worst-case Total
	lb/hr					Total lbs						g/s
Total Hours of Operation	8			8	0					8	0.00	
CO	16.76			16.76	0.00	134.10				134.10	0.00	2.11

Worst-Case 24 Hour Emission Rate

Only SO_2 and PM_{10} are considered for an average 24-hour Ambient Air Quality Standard.

Worst-case 24-Hour Scenario for PM_{10} includes 1 Startup, 1 Shutdown, and remaining time at normal rate.

Worst-case 24-hour scenario for SO_2 uses normal operations.

Emissions per turbine	Worst-case Total	Startup /Warmup	Shutdown	Normal Operations	Worst-case Total	Startup /Warmup	Shutdown		Normal Operations	Worst-case Total
	lb/hr				Total lbs					g/s
Total Hours of Operation	24	0.90	0.900	22.200		0.90	0.900		22.200	
NO_x	2.80	4.17	1.50	2.80	67.26	3.75	1.35		62.16	0.35
CO	3.67	12.50	21.33	2.60	88.17	11.25	19.20		57.72	0.46
VOC	0.71	0.83	0.83	0.70	17.04	0.75	0.75		15.54	0.09
SO_2	0.43	0.44	0.44	0.43	10.43	0.40	0.40		9.64	0.05
PM_{10}	1.85	1.85	1.85	1.85	44.40	1.67	1.67		41.07	0.23

CTG Commissioning testing could operate for 24 hours.

ATTACHMENT D

CTG Emissions Data

low catalyst temps

	1 UNIT	2 UNITS	1 UNIT	2 UNITS	1 UNIT	2 UNITS
Ambient Temperature (°F)	114	114	63.3	63.3	18	18
Stack Diameter (ft)	15	15	15	15	15	15
Exhaust Flow (lb/hr)	780654.0	1561308	840143.5	1680287	883119.0	1766238
Exhaust Flow (acfm)	423776.83	847554	444060.84	888122	441869.49	883739
Stack Exit Velocity, ft/m	2398.09	4796.2	2512.87	5025.7	2500.47	5000.9
Stack Exit Velocity, m/s	12.18	24.36	12.77	25.53	12.70	25.40
Stack Exit Velocity, ft/s	39.97	79.94	41.88	83.76	41.67	83.35
Turbine Outlet Temperature (°F)	830	830	796	796	729	729
CTG Load Level	100%	100%	100%	100%	100%	100%
Evap. Cooler	ON	ON	ON	ON	OFF	OFF

Data from Vendor Area = 176.71 ft^2

high catalyst temps

	1 UNIT	2 UNITS	1 UNIT	2 UNITS	1 UNIT	2 UNITS
Ambient Temperature (°F)	114	114	63.3	63.3	18	18
Stack Diameter (ft)	15	15	15	15	15	15
Exhaust Flow (lb/hr)	723774.5	1447549	777753	1555506	814816	1629632
Exhaust Flow (acfm)	408145.11	816290	428435.38	856871	426215.12	852430
Stack Exit Velocity, ft/m	2309.63	4619.3	2424.45	4848.9	2411.88	4823.8
Stack Exit Velocity, m/s	11.73	23.47	12.32	24.63	12.25	24.50
Stack Exit Velocity, ft/s	38.49	76.99	40.41	80.81	40.20	80.40
Turbine Outlet Temperature (°F)	880	880	849	849	783	783
CTG Load Level	100%	100%	100%	100%	100%	100%
Evap. Cooler	ON	ON	ON	ON	OFF	OFF

Data from Vendor Area = 176.71 ft^2

Expected Operation of Each Gas Turbine - Normal Operation

(Reference: Table 3.4-1 Midway Generating Unit Estimated Performance and Emissions Data FT8-3 Swift Pacs with Foggers)						
Heat Consumed (MMBTU/hr)	290.8	290.8	311.2	311.2	309.5	309.5
Nitrogen, % Vol	73.13	73.13	74.20	74.20	74.69	74.69
Oxygen, % Vol	15.45	15.45	15.50	15.50	15.44	15.44
Carbon Dioxide, % Vol	2.14	2.14	2.26	2.26	2.36	2.36
Argon, % Vol	0.87	0.87	0.89	0.89	0.89	0.89
Water Vapor, % Vol	8.41	8.41	7.15	7.15	6.61	6.61
Molecular Weight	28.22	28.22	28.37	28.37	28.44	28.44

Data from Vendor

Average Emission Rates from Each Gas Turbine (lbs/hr) - Normal Operations

NO_X at 37 ppmvd pre-BACT level	39.10	39.10	41.80	41.80	41.60	41.60
NO_X at 2.5 ppmvd BACT level	2.60	5.30	2.80	5.70	2.80	5.70
CO at pre BACT level	12.40	12.40	13.30	13.30	17.60	17.60
CO ppmvd pre-BACT level	19.00	19.00	19.00	19.00	26.00	26.00
CO at BACT level	2.40	4.80	2.60	5.20	3.40	6.80
CO ppmvd BACT level	3.80	3.80	3.80	3.80	5.00	5.00
VOC at 1.7 ppmvd BACT level	0.60	1.20	0.70	1.40	0.70	1.40
SO_2 short-term rate	0.41	0.81	0.43	0.87	0.43	0.86
SO_2 long-term rate	0.26	0.52	0.28	0.56	0.28	0.55
PM_{10}	1.85	3.70	1.85	3.70	1.85	3.70
NH_3 at 10 ppmvd BACT level	7.30	14.60	7.30	14.60	7.30	14.60

Sulfur content in fuel basis for above: 0.5 grain total S/100 scf short-term

0.32 grain total S/100 scf long-term

Data from Vendor

Startup / Shutdown Emissions from Each Turbine (2 Turbines = 1 SwiftPac Unit)

Startup

duration in minutes	18	18	42	Average	1 hour of
	Startup	Total Startup	Normal	Startup	Startup
	Emissions	Emissions	Emissions	Emissions	Emissions
	lb/event	**lb/event**	lb/hour	lb/hour	lb/hour
NO_X	1.25	1.25	2.80	3.21	4.2
CO	3.75	3.75	3.40	6.13	12.50
VOC	0.25	0.25	1.40	1.23	0.83
SO_2	0.13	0.13	0.43	0.44	0.44
PM_{10}	0.56	0.56	1.85	1.85	1.85

Assumptions:

Startup Emissions for CO, NO_2, PM_{10}, and VOC integrated from data provided by client.

SO_2 emissions assume complete conversion of all sulfur to SO_2.

Normal emissions are highest of six operating cases listed above

NO_x emission estimates from actual CEMS data. VOC and CO emission estimates from client Table 3.4-1A.

PM_{10} emission estimates from normal operations. SO_2 estimates based on 0.5 grains/100 scf natural gas.

Shutdown

duration in minutes	18	42	Average	1 hour of
	Shutdown	Normal	Startup	Shutdown
	Emissions	Emissions	Emissions	Emissions
	lb/event	lb/hour	lb/hr	lb/hour
NO_X	0.45	2.80	2.41	1.50
CO	6.40	3.40	8.78	21.33
VOC	0.25	0.70	0.74	0.83
SO_2	0.13	0.43	0.44	0.44
PM_{10}	0.56	1.85	1.85	1.85

Assumptions:

Shutdown Emissions for CO, NO_2, PM_{10}, and VOC integrated from data provided by client.

SO_2 emissions assume complete conversion of all sulfur to SO_2.

Normal emissions are highest of six operating cases listed above.

NO_x emission estimates from actual CEMS data. VOC and CO emission estimates from client Table 3.4-1A.

PM_{10} emission estimates from normal operations. SO_2 estimates based on 0.5 grains/100 scf natural gas.

ATTACHMENT E

SJVAPCD BACT Guideline 3.4.8

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.8*

Last Update: 10/1/2002

Gas Turbine - < 50 MW, Uniform Load, Without Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	90% control efficiency (SCONOx system, or equal).	
NOx	5.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	1. 2.5 ppmv @ 15% O2 (SCONOx system, or equal). 2. 3.0 ppmv (Dry Low-NOx combustors and SCR, or equal)	
PM10	Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC-regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grams S/100 dscf.		
SOx	PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with < 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	1. 90% control efficiency (SCONOx system, or equal).	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis
(C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0)

I. NO_X Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies achieved in practice BACT as the following:

- 5.0 ppmvd NO_X @ 15% O_2, based on a three-hour average (high temperature SCR, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies technologically feasible BACT as the following:

- 2.5 ppmvd NO_X @ 15% O_2 ($SCONO_X$ system, or equal)
- 3.0 ppmvd NO_X @ 15% O_2 (dry low-NO_X combustors and SCR, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All control options listed in step 1 are technologically feasible.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

The following options are ranked based on their emission factor:

1. 2.5 ppmvd NO_X @ 15% O_2 ($SCONO_X$ system, or equal)
2. 3.0 ppmvd NO_X @ 15% O_2 (dry low-NO_X combustors and SCR, or equal)
3. 5.0 ppmvd NO_X @ 15% O_2, based on a three-hour average (high temperature SCR, or equal)

Step 4 - <u>Cost Effective Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO_X emissions of 2.5 ppmv @ 15% O_2 (1-hour average). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.5 ppmv @ 15% O_2 (1-hour average). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_X emissions of less than or equal to 2.5 ppmv @ 15% O_2 (1-hour average). Therefore, BACT is satisfied.

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2, based on a three-hour average (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies technologically feasible BACT as the following:

- 90% control efficiency ($SCONO_X$ system, or equal – 0.6 ppmvd VOC @ 15% O_2)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 90 control efficiency @ 15% O_2 (0.6 ppmvd @ 15% O_2 per project C-1010207)
2. 2.0 ppmvd @ 15% O_2, based on a three hour average (oxidation catalyst, or equal)

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions. District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required.

Per District practice in previous power plant projects, a SCONOx system and the installation of a bigger oxidation catalyst or additional catalyst material to the existing oxidation catalyst are the only two feasible control alternatives capable of achieving a minimum control efficiency of at least 90% for VOC emissions. Therefore, a cost analysis will be performed for each of these control technologies.

As discussed above, Starwood Power will have two turbines exhausting through one common exhaust stack. Typically, a cost effective analysis would be performed on each emission unit that is triggering BACT requirements for this project. However, since Starwood Power is proposing to exhaust two turbines through one common exhaust stack, the following cost effective analysis will be performed for two turbines combined.

1a. SCONOx System - 90 control efficiency or 0.6 ppmv @ 15% O_2

SCONOx systems typically result in reductions of NO_X, CO and VOC emissions. For control technologies that control more than one type of air pollutant, a multi-pollutant cost effectiveness threshold (MCET) must be calculated. If the total annual cost of the control technology is greater than the MCET, the control technology or equipment under review cannot be required as BACT (Per District policy APR 1305).

As stated in Section VIII (Rule 2201) of this document, BACT is required for NO_x, VOC, PM_{10} and SO_x emissions for each CTG. As stated above, $SCONO_x$ typically results in reductions of NO_x, CO and VOC emissions. Since BACT is not triggered for CO emissions for the purposes of this project, the MCET for this operation can be calculated using the following formula:

MCET ($/yr) = $(E_{NOx} * T_{NOx}) + (E_{VOC} * T_{VOC})$

Where:
E_{NOx} = tons-NO_x controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_x ($9,700/ton-$NO_x$)
T_{VOC} = District's cost effectiveness threshold for VOC ($5,000/ton-VOC)

<u>A. MCET</u>

Uncontrolled emissions from a simple cycle turbine will be considered as the emissions generated from an operation using industry standard materials with no control devices.

<u>NO_X Emissions:</u>

Pursuant to the BACT analysis performed for BACT guideline 3.4.8 under District project C-1010207 (5/12/01), the industry standard NO_X emissions for simple cycle turbine arrangements is 25 ppmvd @ 15% O_2.

The applicant is proposing to operate each of these turbines for up to 4,000 hours per year. Based on an industry standard of NO_X emission rate of 25 ppmvd @ 15% O_2 (equivalent to 0.0921 lb/MMBtu) and the maximum combustor rating of each turbine, the total, uncontrolled annual NO_X emissions are:

Uncontrolled NO_X Emissions, Per Turbine = 0.0921 lb/MMBtu x 311 MMBtu/hr x 4,000 hr/year
Uncontrolled NO_X Emissions, Per Turbine = 114,572 lb/year

Uncontrolled NO_X Emissions, Per SwiftPac = 229,144

SCONOx systems will typically be capable of achieving an outlet NO_X emission concentration of 2.5 ppmvd @ 15% O_2 (equivalent to 0.0092 lb/MMBtu). Therefore, the maximum controlled emissions from each turbine are:

Controlled NO_X Emissions, Per Turbine = 0.0092 lb/MMBtu x 311 MMBtu/hr x 4,000 hr/year
Controlled NO_X Emissions, Per Turbine = 11,445 lb/year

Controlled NO_X Emissions, Per SwiftPac = 22,890

Therefore, the amount of NO_X emissions controlled by a SCONOx system can be calculated as follows:

E_{NOx} = Uncontrolled NO_X Emissions (lb/year) – Controlled NO_X Emissions (lb/year)
E_{NOx} = 229,144 lb/year – 22,890 lb/year

E_{NOx} = 206,254 lb/year (103.1 tons/year)

<u>VOC Emissions:</u>

Pursuant to the BACT analysis performed for BACT guideline 3.4.8 under District project C-1010207 (5/12/01), the industry standard VOC emissions for simple cycle turbine arrangements is 6.25 ppmvd @ 15% O_2.

The applicant is proposing to operate each of these turbines for up to 4,000 hours per year. Based on an industry standard of VOC emission rate of 6.25 ppmvd @ 15% O_2 (equivalent to 0.0080 lb/MMBtu) and the maximum combustor rating of each turbine, the total, uncontrolled annual VOC emissions are:

Uncontrolled VOC Emissions, Per Turbine = 0.0080 lb/MMBtu x 311 MMBtu/hr x 4,000 hr/year
Uncontrolled VOC Emissions, Per Turbine = 9,952 lb/year

Uncontrolled VOC Emissions, Per SwiftPac (two turbines) = 19,904 lb/year

SCONOx systems will typically be capable of achieving an outlet VOC emission concentration of 0.6 ppmvd @ 15% O_2 (equivalent to 0.0008 lb/MMBtu). Therefore, the maximum controlled VOC emissions from each turbine are:

Controlled VOC Emissions, Per Turbine = 0.0008 lb/MMBtu x 311 MMBtu/hr x 4,000 hr/year
Controlled VOC Emissions, Per Turbine = 995 lb/year

Controlled VOC Emissions, Per SwiftPac (two turbines) = 1,990 lb/year

Therefore, the amount of VOC emissions controlled by a SCONOx system can be calculated as follows:

E_{VOC} = Uncontrolled VOC Emissions (lb/year) – Controlled VOC Emissions (lb/year)
E_{VOC} = 19,904 lb/year – 1,990 lb/year

E_{VOC} = 17,914 lb/year (9.0 tons/year)

Using these values, the MCET for a SCONOx system for the purposes of this project is as follows:

MCET ($/yr) = ($E_{NOx}$ * T_{NOx}) + (E_{VOC} * T_{VOC})
MCET ($/yr) = (103.1 ton/year * $9,700/ton) + (9.0 ton/year * $5,000/ton)

MCET = 1,045,070 $/year

B. SCONOx Capital Cost

The District conducted research attempting to determine the cost of installing a $SCONO_X$ system. Starwood Power was able to contact a Mr. James Whitehorn at EmeraChem and briefly discuss with him the scope of the turbine installation project and the cost to install a $SCONO_X$ (EMx) system. Based upon that conversation, Mr. Whitehorn explained that a system for a 60 MW, 622 MMBtu/hr FT-8 SwiftPac would have a capital cost of approximately $4.0 million. The values in the following table, excluding the cost for the basic equipment, were taken from the application review performed for project C-1020647.

Description of Cost	Cost Factor	Cost	Source
Direct Capital Costs (DC):			
Purchase Equipment Costs (PE):			
(A) Basic Equipment: $SCONO_x$ System		4,000,000	EmeraChem
(B) Instrumentation: included in base price		0	OAQPS
PE Total:		**4,000,000**	
Direct Installation Costs (DI): Assume Modular SCR w/simple installation			
Foundation and Supports:	0.08 PE	320,000	OAQPS
Handling and Erection:	0.14 PE	560,000	OAQPS
Electrical:	0.04 PE	160,000	OAQPS
Piping:	0.02 PE	80,000	OAQPS
Insulation:	0.01 PE	40,000	OAQPS
Painting:	0.01 PE	40,000	OAQPS
DI Total:		1,200,000	

Site Preparation and Buildings			
DC Total = PE + DI:		5,200,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	400,000	OAQPS
Construction and Field Expenses:	0.05 PE	200,000	OAQPS
Contractor Fees:	0.10 PE	400,000	OAQPS
Start-up:	0.02 PE	80,000	OAQPS
Performance Testing:	0.01 PE	40,000	OAQPS
Contingencies:	0.03 PE	120,000	OAQPS
IC Total:		1,240,000	
Total Capital Investments (TCI = DC + IC):		6,440,000	

Pursuant to the District BACT Policy section X. (Revised 4/18/95), the annual cost of installing and maintaining the SCONOx system will be calculated as follows. The installation cost will be spread over the expected life of the SCONOx system which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: $A = [P * i(I+1)^n]/[(I+1)^n-1]$

Where:
- A = Annual Cost
- P = Present Value
- I = Interest Rate (10%)
- N = Equipment Life (10 years)

$A = [\$6,440,000 * 0.1 * (1.1)^{10}]/[(1.1)^{10}-1]$

= $1,048,080/year

B. SCONOx Operation and Maintenance Costs

As shown above, the annualized total capital investment to install a SCONOx system is already higher than the MCET value calculated above. Therefore, the total capital cost alone can be used to show that this control technology is not cost effective and that it is not necessary to calculate and include the annualized operation and maintenance costs. No further discussion is necessary.

C. Cost Effectiveness

The annualized total capital investment of utilizing a $SCONO_X$ system ($1,048,080/year) is more than the MCET of $1,045,070/year. Therefore, the use of a SCONOx system as a control technology with a VOC control efficiency of at least 90% is not cost effective and is being removed from consideration at this time.

1b. Additional Oxidation Catalyst - 90 control efficiency or 0.6 ppmv @ 15% O_2

A. Total Cost

Pursuant to information provided by John Lague with URS Corporation (consultant for project), the additional cost of this catalyst would run around $300,000 for each generator unit. Each generator unit is equipped with a turbine on each end. Therefore, as a conservative estimate, it will be assumed that the cost of the additional catalyst for one turbine will be $150,0000.

Pursuant to the District BACT Policy section X. (Revised 4/18/95), the annual cost of installing and maintaining the incinerator will be calculated as follows. The installation cost will be spread over the expected life of the oxidation catalyst which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: A = $[P * i(I+1)^n]/[(I+1)^n-1]$

Where:

A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

A = $[\$300,000 * 0.1 * (1.1)^{10}]/[(1.1)^{10}-1]$
= **$48,824/year**

B. Emission Reductions

Uncontrolled emissions from a simple cycle turbine will be considered as the emissions generated from an operation using industry standard materials with no control devices. Pursuant to the BACT analysis performed for BACT guideline 3.4.8 under District project C-1010207 (5/12/01), the industry standard VOC emissions for simple cycle turbine arrangements is 6.25 ppmvd @ 15% O_2.

The applicant is proposing to operate each of these turbines for up to 4,000 hours per year. Based on an industry standard of VOC emission rate of 6.25 ppmvd @ 15% O_2 (equivalent to 0.0080 lb/MMBtu) and the maximum combustor rating of each turbine, the total, uncontrolled annual VOC emissions are:

Annual VOC Emissions, Per Turbine = 0.0080 lb/MMBtu x 311 MMBtu/hr x 4,000 hr/year
Annual VOC Emissions, Per Turbine = 9,952 lb/year

VOC Reductions, Per Turbine = Uncontrolled VOC PE (lb/year) x CE (%)
VOC Reductions, Per Turbine = 9,952 lb/year x 0.90

VOC Reductions, Per Turbine = 8,957 lb/year
VOC Redutions, Per SwiftPac (two turbines) = 17,914 lb/year

C. Cost of VOC Emission Reduction

The cost of the reductions from the use of additional control which is capable of achieving a minimum VOC control efficiency of 90% is as follows:

Cost of reductions = ($48,824/yr)/(17,914 lb/yr)(1 ton/2000 lb)
= **$5,451/ton of VOC reduced**

The cost of VOC reduction by installing additional catalyst capable of achieving a minimum control efficiency of 90% would be greater than the $5,000/ton cost effectiveness threshold of the District BACT policy. The use of a control technology with a VOC control efficiency of at least 90% is therefore not cost effective and is being removed from consideration at this time.

2. 2.0 ppmvd @ 15% O_2, based on a three hour average

Per the District BACT Policy, a cost effective analysis is not required for a control technology that has been determined to be achieved in practice. As discussed above, turbines operating with VOC emissions of 2.0 ppmvd @ 15% O_2 has been determined to be achieved in practice for this class and category of operation. Therefore, a cost effective analysis for this control technology is not required and will not be performed for this project.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer, and either PUC-regulated natural gas, LPG, or non-PUC regulated natural gas with < 0.75 grains S/ 100 dscf

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer, and either PUC-regulated natural gas, LPG, or non-PUC regulated natural gas with < 0.75 grains S/ 100 dscf.

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air inlet cooler/filter, lube oil vent coalescer, and PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet cooler/filter, lube oil vent coalescer and PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf. Starwood Power is proposing to use an air inlet cooler/filter, lube oil vent coalescer and PUC-regulated natural gas fuel; therefore, BACT is satisfied.

IV. SO_X Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.8 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All of the listed controls are considered technologically feasible for this application.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

1. PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, or equal.

Step 4 - <u>Cost Effectiveness Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf. Starwood Power has proposed to fire each of these turbines on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review

TO: Dustin Brown, AQE--Permit Services

FROM: Leland Villalvazo, SAQS--Technical Services

DATE: March 26, 2007

SUBJECT: Starwood Power-Midway, LLC

LOCATION: 43699 Panoche Rd, Firebaugh, CA

APPLICATION #: C-7286-1-0 thru 4-0

PROJECT #: N-1063535

A. RMR SUMMARY

Categories	1-0 NG Turbine	2-0 NG Turbine	3-0 NG Turbine	4-0 NG Turbine	Project Totals	Facility total
Prioritization Score	24.55	24.55	24.55	24.55	**98.2**	**98.2**
Acute Hazard Index	0.0	0.0	0.0	0.0	**0.0**	**0.0**
Chronic Hazard Index	0.0	0.0	0.0	0.0	**0.0**	**0.0**
Cancer Risk (10^{-6})	0.101	0.101	0.101	0.101	**0.404**	**0.404**
T-BACT Required?	**No**	**No**	**No**	**No**	**N/A**	**N/A**
Special Permit Conditions?	**No**	**No**	**No**	**No**	**N/A**	**N/A**

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels, the following permit conditions must be included:

1-0 thru 4-0

No special conditions required.

B. RMR REPORT

I. Project Description

Technical Services received a request on February 15, 2007, to perform a Risk Management Review and an AAQA for the proposed Installation of a new power plant. The facility will include four Natural gas Turbines with ammonia slip.

II. Analysis

Toxic emissions for the four turbines were calculated using Ventura County's emission factors for external combustion sources. The engineer supplied the ammonia emissions. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905-1, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for these proposed units was greater than 1.0 (see RMR Summary Table). Therefore, a refined analysis was necessary.

The following parameters were used for the review (Single or Double Turbine Mode):

POINT SOURCES:

Process	Stack Diameter (m)	Exhaust Height (m)	Gas Exit Flowrate (m/s)	Exhaust Temperature (°K)	Exhaust Direction
Single Turbine	4.573	15.244	12.76502	697.590	Vertical
Double Turbine	4.573	15.244	25.53005	697.590	Vertical

III. RMR Conclusion

Several operational scenarios were modeled. The results of the worst-case scenario are documented in the RMR Summary Table on page one. The chronic and the acute risk were below one and the cancer risk for this project is less than one in a million. **Therefore, in accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risk will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for each proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

IV. AAQA

Technical Services also performed modeling for criteria pollutants CO, NOx, SOx, and PM_{10}; as well as the RMR. The emission rates used for criteria pollutant modeling were as follows

Pollutant/Unit	1-0		2-0		3-0		4-0	
	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr
NOx	41.65	11,208	41.65	11,208	41.65	11,208	41.65	11,208
CO	21.33	19,547	21.33	19,547	21.33	19,547	21.33	19,547
PM10	1.85	7,400	1.85	7,400	1.85	7,400	1.85	7,400
SOx	0.89	3,560	0.89	3,560	0.89	3,560	0.89	3,560

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in $\mu g/m^3$

	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	**X**	Pass	**X**	**X**
NO_x	Pass	**X**	**X**	**X**	Pass
SO_x	Pass	Pass	**X**	Pass	Pass
PM_{10}	**X**	**X**	**X**	Pass[1]	Pass[1]

*Results were taken from the attached PSD spreadsheets.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

V. AAQA Conclusion

The criteria modeling runs indicate the emissions from the proposed equipment will not cause or significantly contribute to a violation of a State or National AAQS. Therefore, no further modeling will be required and permitting may proceed as proposed.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Attachments:

A. Individual Unit risk break down for future modeling
B. RMR Request from the Project Engineer
C. HARP Risk Results
D. Emissions Spreadsheets
E. AAQA/PSD Spreadsheets

AAQA for Starwood Powr - Midway LLC Units 1-0 thur 7-0 (C-7286)
All Values are in ug/m^3

Three Turbins	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
One Turbin STACK1	1.002E+02	6.767E-03	6.383E+01	1.044E+01	2.855E+00	9.566E-01	1.556E-01	2.866E-03	3.235E-01	5.957E-03
Two Turbine STACK2	4.623E-02	1.174E-02	1.576E-01	7.987E-03	6.578E-03	2.569E-03	4.742E-04	4.970E-03	9.858E-04	1.033E-02
Background	1.607E+02	3.252E+01	4.777E+03	3.495E+03	5.062E+01	2.398E+01	1.066E+01	5.330E+00	1.060E+02	3.900E+01
Facility Totals	2.609E+02	3.254E+01	4.840E+03	3.505E+03	5.348E+01	2.494E+01	1.082E+01	5.338E+00	1.063E+02	3.902E+01
AAQS	470	100	23000	10000	655	1300	105	80	50	30
	Pass	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Fail**	**Fail**

EPA's Significatance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	**1.0**	**2000.0**	**500.0**	**0.0**	**25.0**	**5.0**	**1.0**	**5.0**	**1.0**

PASS FAIL

Two Turbins Total 200.4

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Starwood Power-Midway Power Plant

Facility Name:	Starwood Power-Midway, LLC	Engineer:	Dustin Brown
Mailing Address:	591 W. Putnam Avenue Greenwich, CT 06830	Date:	March 12, 2007
Contact Person:	Richard Weiss	Lead Engineer:	Joven Refuerzo
Telephone:	(713) 662-3688		
Application #:	C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0		
Project #:	C-1063535		
Location:	43699 W. Panoche Road in Firebaugh, CA		
Complete:	December 29, 2006		

I. Proposal

Starwood Power-Midway, LLC, hereinafter referred to as "Starwood Power", is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "peaking" electrical power generation facility. Starwood Power will be a simple-cycle electrical power generation facility consisting of four natural gas-fired combustion turbine generators (CTG's). The plant will have a nominal rating of 120 megawatts (MW).

Starwood Power is considered the same stationary source as the existing Cal Peak Power-Panoche, LLC facility (C-3811) that is located right next to the proposed site location. This stationary source (facility's C-3811 and C-7286 combined) will become a major source for NO_X emissions after this proposed project. There will be an increase in emissions for all criteria pollutants and offsets will be required for NO_X and PM_{10} emissions.

Starwood Power is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
(Section 3.30 and 4.13.3.2)

III. Process Description

Starwood Power will consist of two Pratt & Whitney, model FT8-3 SwiftPac, Gas Turbine Generator units. Each SwiftPac unit will have two Pratt & Whitney, model FT8-3, natural gas fired turbines that will drive opposite ends of a single electric generator. Each generator will produce electricity at a nominal output of 60 MW. The total facility nominal output will be 120 MW. No cooling towers or heat recovery steam generators (HRSG's) will be installed. In addition, the applicant has not proposed any black start equipment.

The two FT8-3 SwiftPac units will be installed in a simple cycle power plant arrangement. Each CTG is equipped with water injection into the combustors to reduce production of nitrogen oxides (NO_X), a selective catalytic reduction (SCR) system with ammonia injection to further reduce NO_X emissions, an oxidation catalyst to reduce Carbon Monoxide (CO) emissions, and associated support equipment.

The CTG's will operate during periods of peak electricity demand. Peak electricity demand periods typically occur during daylight hours in the second and third quarters of the calendar year, but can also occur during other periods when unusual temperature extremes cause unseasonably high electricity demand or when other electricity resource constraints reduce the amount of power otherwise available to the grid. This facility could operate during any of these periods.

The facility has proposed an annual operating scenario of 3,781 hours of full load operation per year and 219 hours in startup or shutdown mode. Starwood Power does not wish to be restricted to a specific number of hours at full load operation or startup/shutdown operation per calendar quarter. Actual emissions from the facility will vary depending on electricity demand from California. A hypothetical operating scenario has been developed for purposes of demonstrating that the project will comply with SJVAPCD emission offset requirements.

Starwood Power-Midway – Hypothetical Operating Scenario (per unit)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startup/Shutdown Hours	43.8	43.8	76.65	54.75	219
Number of Full Load Hours	756.2	756.2	1,323.35	945.25	3,781
Total Hours	800	800	1,400	1,000	4,000

IV. Equipment Listing

C-7286-1-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-2)

C-7286-2-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-1)

C-7286-3-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-4)

C-7286-4-0: 30 MW NOMINALLY RATED SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A 311 MMBTU/HR PRATT & WHITNEY MODEL FT8-3 SWIFTPAC NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER INJECTION, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND A OXIDATION CATALYST POWERING A 60 MW NOMINALLY RATED ELECTRICAL GENERATOR (SHARED WITH C-7286-3)

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

District Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERC's to offset PM_{10} increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*

4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The applicant has proposed to offset the increases in PM_{10} emissions associated with this project by using SO_X ERC's. Per submittal, the applicant has demonstrated the SO_X-to-PM_{10} precursor relationship for this location. Based on that relationship and their analysis, Starwood Power is proposing that SO_X emissions shall be used to offset PM_{10} emissions at a ratio of 1.80:1 (see applicant's analysis in Appendix 1). The proposed SO_X for PM_{10} interpollutant offset ratio demonstrates that their SO_X reduction package has greater PM_{10} reduction as if PM_{10} offsets were used.

The District performed an analysis via a chemical mass balance model using Fresno County modeling data. Fresno County modeling data is valid for all projects in the Fresno or Madera County regions. The SO_X for PM_{10} interpollutant ratio of 1.867:1 was established by the District via a chemical mass balance model was similar to the analysis performed for the San Joaquin Valley Energy Partners project (see District's analysis in Appendix 2). Upon review of the District's analysis, the applicant has agreed to the use of the above interpollutant offset ratio. The originating location of reduction of the proposed ERC certificate is greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5:1 applies. Combining the interpollutant and distance offset ratios; an overall SO_X for PM_{10} offset ratio of 2.8:1 (1.867: x 1.5:1) will be used for the purposes of project C-1063535.

VI. Project Offset Calculations

The following shows the offset requirements and calculations for PM_{10} emissions.

Maximum annual PM_{10} emissions occur when each CTG operates 4,000 hours at full load. The results are summarized in the table below:

Maximum Annual PE (all four CTG's combined)	
Permit Unit	PM_{10} (lb/year)
C-7286-1	7,400
C-7286-2	7,400
C-7286-3	7,400
C-7286-4	7,400
Annual PE	29,600

Pursuant to Section 4.10 of District Rule 2201, the Post-project Stationary Source Potential to Emit (SSPE2) is the post-project annual PE of all units at the Stationary Source.

As discussed above, Starwood Power is considered part of the same stationary source as the existing Cal Peak Power – Panoche, LLC facility located next to the proposed site location. Therefore, the total PM_{10} emissions from this stationary source are the total of both of these facilities combined.

Post-project Stationary Source Potential to Emit [SSPE2]	
Permit Unit	PM_{10} (lb/year)
C-3811-1	10,112
C-3811-2	
C-7286-1	7,400
C-7286-2	7,400
C-7286-3	7,400
C-7286-4	7,400
Post-project SSPE (SSPE2)	39,712

Per District Rule 2201, Sections 4.7.2 and 4.7.3, the quantity of offsets, in pounds per year, is calculated as follows for sources with an SSPE1 less than or equal to the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Stationary Source Potential to Emit
ICCE = Increase in Cargo Carrier Emissions
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

SSPE2 (PM_{10}) = 39,712 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(39,712 – 29,200 + 0) x DOR]
= 10,512 lb/year x DOR

Starwood Power will be limited to the quarterly emission rates calculated in Section VII.C.2.c above. The quarterly PM_{10} emission values are based on the following operating scenario: quarter 1 – 800 hours (20% of allowable annual operation); quarter 2 – 800 hours (20% of allowable annual operation); quarter 3 – 1,400 hours (35% of allowable annual operation); and quarter 4 – 1,000 hours (25% of allowable annual operation). Based on these operational percentages, the appropriate quarterly emissions to be offset without the distance offset ratio as follows:

Quantity of Offsets Required (without DOR)					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	2,102	2,103	3,679	2,628	10,512

As a worst case, the District will assume that the ERC credits that Starwood Power does obtain will have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio (DOR) of 1.5:1 is applicable.

Multiplying the interpollutant offset ratio discussed above (1.867:1) with the distance offset ratio (1.5:1), an overall offset ratio of 2.8:1 is required for utilizing SO_X ERC's for the required PM_{10} offsets. Therefore the amount of SO_X ERC's that need to be withdrawn for PM_{10} offsets for this project is as follows:

PM_{10} Offsets Required (lb/year) = 10,512 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/yr)
PM_{10} Offsets Required	2,102	2,103	3,679	2,628	
Distance Ratio (greater than 15 miles)	1.5	1.5	1.5	1.5	
Proposed Interpollutant Ratio	1.867	1.867	1.867	1.867	
Interpollutant x Distance Ratio (Overall Ratio)	2.8	2.8	2.8	2.8	
Offset Reqmt x Overall Ratio	5,886	5,888	10,301	7,359	29,434

The applicant has stated that the facility plans to use ERC certificate S-2459-5 (or a certificate split from that certificate) to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased 45.0 tons per year of the above certificate, which has available quarterly SO_X credits as follows:

	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/yr)
ERC Certificate #S-2403-5 (available)	37,448	37,535	38,534	52,296	165,813
ERC's Purchased for Project (per signed purchase agreement)	21,500	21,500	25,500	21,500	90,000

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

VII. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 2.8:1 (1.867: x 1.5:1).

VIII. Recommendation

Compliance with all applicable rules and regulations is expected. Issue preliminary determination of compliance for units C-7286-1-0, C-7286-2-0, C-7286-3-0 and C-7286-4-0 with a SO_X for PM_{10} interpollutant offset ratio of 1.867:1.

Appendices

1: Applicant Interpollutant Offset Ratio Proposal Justification
2: District Review and Approval

Appendix 1

Applicant Interpollutant Offset Ratio Proposal Justification

Starwood Midway Project
PM10 Interpollutant Offset Ratio Analysis

PM10

	Notes	Units	Estimate	Uncertainty
"Vegetative Burning" Total	1	$\mu g/m^3$	7.50	2.43
Industry Component (30%)	2	$\mu g/m^3$	2.25	
Regional Background (20%)	3	$\mu g/m^3$	0.45	
Industry minus Background		$\mu g/m^3$	1.80	
County Contribution	4	$\mu g/m^3$	0.90	
Organic Carbon PM10 Inventory - Kern Cou	5	ton/day	5.63	
County Impact		$\mu g/m^3$ per ton	0.16	0.21

Sulfate

	Notes	Units	Estimate	Uncertainty
Ammonium Sulfate	6	$\mu g/m^3$	2.60	0.29
Regional Background	7	$\mu g/m^3$	1.00	
Ammonium Sulfate minus Background		$\mu g/m^3$	1.60	
County Contribution	8	$\mu g/m^3$	0.80	
SOx Inventory - Kern County	9	ton/day	9.08	
County Impact		$\mu g/m^3$ per ton	0.09	0.10
Tons of SOx to Equal Effect of 1 ton PM10	10		1.81	2.16

1. Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources a in the Vegetative Burning category from Chemical Mass Balance modeling performed for the 2003 PM10 Attainment Plan (Bakersfield - Golden State monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previo adjustment to Vegetative Burning category.
4. Contribution from sources within Kern County is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Kern County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUA 2003 PM10 Attainment Plan (Bakersfield - Golden State monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 $\mu g/m^3$.
8. Contribution from sources within Kern County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. SOx inventory for Kern County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM10 County Impact divided by Ammonium Sulfate County Impact.

Supplement C
Development of NOx/PM_{10} and $SO_2/PM10$ Inter-pollutant Offset Ratio for Fresno County

1.0 Introduction

The San Joaquin Valley Unified Air Pollution Control District is a PM_{10} non-attainment area with respect to both the federal and California ambient standards for this pollutant. The Starwood Power-Midway, LLC Peaking Project proposed for Fresno County would result in PM_{10} emissions from various onsite stationary source units. Because the background concentrations already exceed the National and California ambient standards for this pollutant, such emissions increases in PM_{10} have the potential to exacerbate existing exceedances. Accordingly, SJVAPCD regulations require a project that will cause an increase in PM_{10} emissions to provide offsets in sufficient amounts to provide a net air quality benefit.

Reductions of SO_x and NO_x emissions can be used to offset the PM_{10} impact from a new source within the SJVAPCD, because sulfates and nitrates are precursors of particulate matter. In order to quantify the offset requirement when such interpollutant trading is used, the appropriate ratios between PM_{10} and SO_x and PM_{10} and NO_x must be calculated. According to SJVAPCD policy (Sweet, 2006), inter-pollutant trading ratios specific to the Panoche project area can be calculated using results of Chemical Mass Balance (CMB) modeling conducted by SJVAPCD staff as part of the District's 2003 PM_{10} Attainment Plan. As recently as the spring of 2006, URS was informed by SJVAPCD that the assumptions, monitoring data, emissions inventory data and calculation methods used in the Attainment Plan are sufficiently recent to be considered valid for the purpose of estimating current SO_x/PM_{10} and NO_x/PM_{10} interpollutant offset ratios.

2.0 CMB Modeling Results and Annual Roll Back Analysis

Receptor modeling using the chemical mass balance model was conducted by SJVAPCD for sites in the project area that currently do not comply with the federal PM_{10} air quality standards. This method uses chemical analysis of collected air monitoring samples and information about the chemical composition of contributing sources to evaluate the link between observed concentrations and contributing emission sources. The SJVAPCD used the results of its CMB analysis with a modified rollback approach to calculate the effects on design particulate values that would result from implementation of adopted and proposed control measures to reduce PM_{10} pollution and other predicted emission trends for the most recent PM_{10} Attainment Plan. The results can also be used to support calculation of interpollutant offset ratios, as described later. The data used for this purpose were taken from an Excel workbook titled N2-Annual Rollback Analysis which was provided by SJVAPCD. Tables 1-4 summarize the data from the N2 Rollback Analysis that are relevant to this application

Table 1 presents monthly and annual average CMB modeling results for Fresno County. This includes measured PM10 concentrations at the Fresno Drummond monitoring site and model predicted contributions to these concentrations due to various source types. Table 2 shows the annual average CMB modeling results and design values for the SJVAPCD areas that are noncompliant with the PM_{10} standards from Table 1, including Fresno Drummond results. The design values were determined using EPA calculation methods (EPA 2004) and the air quality monitoring data collected in Fresno County. In Table 2, 'Sum of Species' represents the summation of the mass concentrations across all source categories, including 'Burning', 'Motor Vehicle', 'Tire/Brake', 'Sulfate', 'Nitrate', and 'Geological'. The value difference between 'Sum of Species' and 'Design Value' was left in the "unassigned" column.

The rollback analyses conducted by SJVAPCD used a speciation model with the CMB results. This modified rollback analysis showed not only the speciation, but also how the species were distributed and estimated source attributions for both primary and secondary pollutant species. The rollback analysis also considered other factors, including geological information, PM, VOC, and NO_x inventory totals, and other relevant information. Separate modeling was conducted in the rollback analysis for each county to account for conditions and characteristics that are unique to specific areas of the SJVAPCD. The rollback analysis for Fresno County is shown in the tab labeled "Fresno" within the Excel Workbook provided in Attachment 1 "N2-Annual Rollback Analysis".

The SJVAPCD rollback analysis was conducted as follows. Line 1 in Table 3 shows the concentration values influenced by the local area emissions. The 'Annual design value' equivalent to the chemistry of the CMB monthly analysis of the Fresno Drummond data in the Table 2 matches with the 'General Note' in Line 1 of Table 3. The mass concentrations of 'Geological', 'Mobile', 'Tire/Brake', and 'Unassigned' in Table 2 are equivalent to the corresponding attributes in line 1 of Table 3. The cells in Line 1 for vegetative burning and organic carbon represent 70% and 30% respectively of the value for 'Burning' in Table 2.

Line 2 of Table 3 shows concentration values for the natural and transport contributions for each attribute, which come from background concentration measurements. Line 3 is the 'net for rollback' concentrations, which means the differences in values between Line 1 and Line 2. The values of Line 3 are distributed to Line 4 through Line 7 based on the area of influence and the percentage distribution of PM10 source categories used by SJVAPCD. The attributes of 'Geological and Construction', 'Tire/Brake', and 'Unassigned' follow the corresponding percentages of PM_{10} distribution. The attributes of 'Mobile', 'Organic Carbon', 'Vegetation Burning', 'Ammonium Nitrate', and 'Ammonium Sulfate' follow the percent of $PM_{2.5}$ distribution. Lines 4 and 5 represent the local contribution of $PM_{2.5}$ minus PM_{10} and $PM_{2.5}$, respectively. Line 6 presents the sub-regional contribution, and Line 7 shows the regional contributions.

The most current emission inventory (lb/day) for PM_{10}, NO_x, total organic compounds (TOG) and SO_x for the Fresno-Madera area is provided in Table 4.

Values from Tables 3 and 4 were used to calculate the inter-pollutant trading ratio for Fresno County. The methods employed for these calculations are addressed in the next section.

Table 1 Monthly and Annual Average CMB results at the Fresno Drummond site for February to December 2000 plus the January 2001 Episode (all concentrations are in µg/m^3)

Fresno Drummond Monthly							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITE ID	DATE	CONC	UCONC	PCMASS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.345	0.329	2.1	1.4			2.327	0.226	2.4774	0.3211	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6
Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Note:
CONC: concentration
UCONC: Uncertainty of concentration
PCMASS: Percent of mass
RSQ: R square
CHISQ: Chi square
Mass: concentration based on mass
UNC: Uncertainty of concentration based on mass

Table 2 **Annual Average CMB results and Design Value for the Counties Noncompliant with the Standards (50) in San Joaquin Valley Unified Air Pollution Control District (All concentrations in $\mu g/m^3$)**

SITE ID	CONC	UCONC	PCMASS	Design Value *	Sum of species	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological		Geological	Un-assigned
						Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Profile	
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	**49.5**	**3.2**	**98.4**	**50.0**	**46.9**	**7.5**	**2.4**	**4.6**	**2.8**	**0.7**	**0.7**	**2.6**	**0.3**	**12.0**	**1.1**	**19.5**	**3.3**	**FDFSDANN**	**3.1**
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

Note:

* All Design Values are equal to or exceed the California 24-Hour Standard (50 $\mu g/m^3$)

BGS: Bakersfield Golden State for Kern County

FSD: Fresno Drummond for Fresno County

HAN: Hanford for Kings County

VCS: Visalia Church Street for Tulare County

Unassigned: Mass based concentration that CMB model did not assign to attribute.

Table 3
SJVAPCD N2 Annual Rollback Analysis (Concentrations on Lines 1 through 7 are in $\mu g/m^3$)

Fresno - Drummond, Annual, Design value = 50 μg/m3	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB	From CMB	Estimated portion of mass included in Vegetative Burning =30%	From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any.
LINE 1	**50.00**	**19.50**	**4.60**	**0.70**	**2.25**	**5.25**	**12.00**	**2.60**	**0.00**	**3.1**
Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0	0, no natural background, transport estimated at 0	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions. = 20%	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic. =20% + 10%	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
LINE 2	**8.25**	**4.0**	0.0	0.0	0.7	**1.6**	1.0	1.0		
Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except						Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	

Fresno - Drummond, Annual, Design value = 50 μg/m3	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
	as indicated.									
LINE 3 Line4 Local Contribution PM2.5-PM10 Area of Influence	**41.75** Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	**15.5** 70%PM10 50%PM2.5 of net	**4.6** 70%PM10 50%PM2.5 of net	**0.7** 70%PM10 50%PM2.5 of net	**1.6** 70%PM10 50%PM2.5 of net	**3.7** 70%PM10 50%PM2.5 of net	**11.0** 70%PM10 50%PM2.5 of net, non-linear rollback	**1.6** 70%PM10 50%PM2.5 of net	**0.0**	**3.1** 70%PM10 50%PM2.5 of net
LINE 4 Line5 Local Contribution Area of Influence of PM2.5	**24.74** Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	**10.9** 15%PM10 30%PM2.5	**2.3** 15%PM10 30%PM2.5	**0.5** 15%PM10 30%PM2.5	**0.8** 15%PM10 30%PM2.5	**1.8** 15%PM10 30%PM2.5	**5.5** 15%PM10 30%PM2.5 non-linear rollback	**0.8** 15%PM10 30%PM2.5		**2.2** 15%PM10 30%PM2.5
LINE 5 Line6 Sub regional Contribution	**9.63** Rolled back against specified County(ies) emission estimates - episode specific	**2.3** 10%PM10 15%PM2.5	**1.4** 10%PM10 15%PM2.5	**0.1** 10%PM10 15%PM2.5	**0.47** 10%PM10 15%PM2.5	**1.1** 10%PM10 15%PM2.5	**3.3** 10%PM10 15%PM2.5 non-linear rollback	**0.5** 10%PM10 15%PM2.5		**0.5** 10%PM10 15%PM2.5

Fresno - Drummond, Annual, Design value = 50 $\mu g/m^3$	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
	adjustments based on meteorology and episode duration									
LINE 6 Line7 Regional Contribution	**5.30** Rolled back against Valley-wide emission estimates - episode specific adjustments based on meteorology and episode duration	**1.6** 5%PM10 5%PM2.5	**0.7** 5%PM10 5%PM2.5	**0.1** 5%PM10 5%PM2.5	**0.24** 5%PM10 5%PM2.5	**0.6** 5%PM10 5%PM2.5	**1.65** 5%PM10 5%PM2.5 non-linear rollback	**0.24** 5%PM10 5%PM2.5	[illegible]	**0.3** 5%PM10 5%PM2.5
LINE 7 Associated Emissions Categories	**2.09** Based upon appropriate seasonal or annual inventory	**0.8** PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	**0.2** PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass	**0.0** Tire and brake wear as predicted by EMFAC2002	**0.08** Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass	**0.2** PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	**0.55** Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	**0.08** Total SOx	[illegible] None, natural emission from the ocean, bay and delta waters	**0.2** Total PM10

Table 4 Emission Inventory for Year 1999 through Current Year (valid for this project)- All emissions in tons per day

Emissions Inventory	Area of Influence	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
PM10	Fresno	74.4504	4.1236	0.511	5.6266	10.4843				39.92145356
NOx	Fresno						174.7763			
TOG	Fresno		58.2653		396.7168					
SOx	Fresno							9.0772		

3.0 Interpollutant Trading Ratio

The SJVAPCD (Sweet, 2005) provided the interpollutant trading calculation method, which is presented in Tables 5, 6, and 7. Summing 'organic carbon' and 'vegetation burning' from Line 1 in Table 3 gave the value of 'Vegetative Burning Total' in Table 5. 'Industry Component' and 'Regional Background' were calculated as 30% and 20% of the'Vegetative Burning Total', respectively. The value for 'Regional Background' was subtracted from the 'Industry Component' to obtain the 'Industry minus Background' value. The value for 'County Contribution' was estimated to be 50% of the value of 'Industry minus Background'. The value for 'Organic Carbon PM_{10} Inventory-Fresno County' was obtained from the emission inventory shown in Table 4. The value for 'County Contribution' divided by the value of 'Organic Carbon PM_{10} Inventory' gave the 'County Impact' in units of $\mu g/m^3$ per ton.

The values of 'Ammonium Sulfate' and 'Regional Background' in Table 6 were obtained from the values of 'Ammonium Sulfate' in Lines 1 and 2 in Table 4, respectively. The value of 'Ammonium Sulfate' was reduced by the value of 'Regional Background' to obtain the entry labeled 'Ammonium Sulfate minus Background'. The value for 'County Contribution' was also determined as 50% of the value of 'Ammonia Sulfate minus Background'. The value of 'SO_x Inventory-Fresno County' was obtained from the emission inventory shown in Table 4. The value of 'County Contribution' divided by the value of 'SO_x Inventory' gave the 'County Impact' in units of $\mu g/m^3$ per ton.

The inter-pollutant trading ratio of SO_2 to PM_{10} was calculated as the ratio of the 'County Impact' of PM_{10} to the 'County Impact' of SO_x. The ratio is 1.8 (tons of SO_2 to equal the effect of 1 ton of PM_{10} reduction). Likewise, the interpollutant trading ratio of NO_2 to PM_{10} was calculated in Table 7 as a ratio of the 'County Impact' of PM_{10} to the 'County Impact' of NO_x. The resulting ratio is 3.0 (tons of NO_2 to equal the effect of reducing 1 ton of PM_{10}).

Table 5 PM$_{10}$ County Impact

PM$_{10}$	Note	Units	Estimate	Uncertainty
"Vegetative Burning" Total	1	$\mu g/m^3$	7.50	2.43
Industry Component (30%)	2	$\mu g/m^3$	2.25	
Regional Background (20%)	3	$\mu g/m^3$	0.45	
Industry minus Background		$\mu g/m^3$	1.80	
County Contribution	4	$\mu g/m^3$	0.90	
Organic Carbon PM$_{10}$ Inventory - Fresno County	5	ton/day	5.63	
County Impact		$\mu g/m^3$ per ton	0.16	0.21

Table 6 SO$_x$ County Impact and Inter-pollutant trading ratio of SO$_x$ and PM$_{10}$

Sulfate	Note	Units	Estimate	Uncertainty
Ammonia Sulfate	6	$\mu g/m^3$	2.60	0.29
Regional Background	7	$\mu g/m^3$	1.00	
Ammonium Sulfate minus Background		$\mu g/m^3$	1.60	
County Contribution	8	$\mu g/m^3$	0.80	
SO$_x$ Inventory - Fresno County	9	ton/day	9.08	
County Impact		$\mu g/m^3$ per ton	0.09	0.10
Tons of SO$_x$ to Equal Effect of 1 ton PM$_{10}$ Reduction	10		**1.8**	2.2

Table 7 NOx County Impact and Inter-pollutant trading ratio of NO$_x$ and PM$_{10}$

Nitrate	Note	Units	Estimate	Uncertainty
Ammonium Nitrate	11	$\mu g/m^3$	12.00	0.29
Regional Background	12	$\mu g/m^3$	1.00	
Ammonium Nitrate minus Background		$\mu g/m^3$	11.00	
County Contribution	13	$\mu g/m^3$	5.50	
NOx Inventory - Fresno	14	ton/day	174.7763	
County Impact		$\mu g/m^3$ per ton	0.03	0.03
Tons of NO$_x$ to Equal Effect of 1 ton PM$_{10}$ Reduction	15		**3.0**	4.0

Note:

1. Per SJVUAPCD and CARB, PM$_{10}$ emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM$_{10}$ Attainment Plan (Fresno-Drummond monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
4. Contribution from sources within Fresno County is estimated to be 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM$_{10}$ inventory for Fresno County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on Central California Ozone Study (CCOS) study.

6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM_{10} Attainment Plan (Fresno-Drummond monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 mg/m^3.
8. Contribution from sources within Fresno is estimated to be 50% of net concentration after previous adjustment to Vegetative Burning category.
9. SO_x inventory for Fresno that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM_{10} County Impact divided by Ammonium Sulfate County Impact.
11. Ammonium nitrate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM_{10} Attainment Plan (Fresno - Drummond monitoring station).
12. Per SJVUAPCD, regional background of ammonium nitrate is estimated to be 1 mg/m^3.
13. Contribution from sources within Fresno County is estimated to be 50% of net concentration after previous adjustment to Vegetative Burning category.
14. NO_x inventory for Fresno County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on Central California Ozone Study (CCOS) study.
15. PM_{10} County Impact divided by Ammonium Nitrate County Impact.

4.0 Reference

1) EPA-CMB8.2 Users Manual, December, 2004
2) San Joaquin Valley Air Pollution Control District State Implementation Plan PM10 Modeling Protocol (SJVAPCD, 2005)
3) Attachment 6 and calculation method obtained from SJVAPCD (James Sweet, james.sweet@valleyair.org, 559-230-5810)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Fresno - Drummond, Annual, Design value = 50**	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent in annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any
3	LINE 1	50.00	19.50	4.60		0.70	2.25		5.25	12.00	2.60	0.00	3.1
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions =30%		see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic. [illegible]	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	8.25	4.0	0.0		0.0	0.7		1.6	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	41.75	15.5	4.6		0.7	1.6		3.7	11.0	1.6	0.0	3.1
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	24.74	10.9	2.3		0.5	0.8		1.8	5.5	0.8		2.2
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	9.63	2.3	1.4		0.1	0.47		1.1	3.3	0.5		0.5
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	5.30	1.6	0.7		0.1	0.24		0.6	1.65	0.24		0.3
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.09	0.8	0.2		0.0	0.08		0.2	0.55	0.08		0.2
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E I NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	1999 Emissions Inventory	(area of influence emissions inventory, each on a separate line for automated calculations)											
18	PM10	L1= Area 3	7.236852297	1.55746265		0.270246847	1.54732371		2.946320228				15.67865618
19		L2= Areas 3,4	26.02510179	2.26760773		0.375484581	2.955506973		5.732736172				39.92145356
20		Sr= Fresno, Madera	74.4504	4.1236		0.511	5.6266		10.4843				94.6839
21		R= SJV	230.9463	14.9086		1.92	24.7498		34.9152				305.5217
22	NOx	L1= Area 3								53.21489079			
23		L2= Areas 3,4								88.61773631			
24		Sr= Fresno, Madera								144.7763			
25		R= SJV								565.19			
26	TOG	L1= Area 3			22.7065618			132.7691237					
27		L2= Areas 3,4			33.470797			257.8874576					
28		Sr= Fresno, Madera			58.2653			396.7168					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 3									3.438823609		
31		L2= Areas 3,4									5.665348981		
32		Sr= Fresno, Madera									9.0772		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Fresno - Drummond, Annual, Design value = 50**	**General Note**	**Geologic and Construction**	**Mobile Exhaust**		**Tire and Brake Wear**	**Organic Carbon**		**Vegetative Burning**	**Ammonium Nitrate including associated water**	**Ammonium Sulfate**	**Marine**	**Unassigned**
133	**2010-2011 Emissions Inventory**												
134	PM10 2010 EI without new controls	L1= Area 3	8.129557667	1.44348865		0.367960339	1.747683078		3.262499732				17.31537711
135		L2= Areas 3,4	29.27326116	2.15521975		0.543853899	3.283460261		6.107828372				44.15866903
136		Sr= Fresno, Madera	83.727	3.8288		0.746828157	6.2618		10.8882				104.7058
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= Area 3	6.809440309	1.38943472		0.367960339	1.5244012		2.650942087				15.31076142
139		L2= Areas 3,4	24.51972576	2.07451381		0.543853899	2.863986791		4.962912068				37.05429637
140		Sr= Fresno, Madera	70.131	3.68542395		0.746828157	5.4618		8.8472				84.47342395
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2898				265.2426
142	NOx 2010 EI without new controls	L1= Area 3								34.57241458			
143		L2= Areas 3,4								62.07171354			
144		Sr= Fresno, Madera								103.4162			
145		R= SJV								401.6368			
146	NOx 2010 EI with new controls	L1= Area 3								31.73589191			
147		L2= Areas 3,4								56.97898788			
148		Sr= Fresno, Madera								94.93133136			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 3			11.5234286			156.7815607					
151		L2= Areas 3,4			17.8329166			304.4959518					
152		Sr= Fresno, Madera			31.9684			468.3626					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 3			11.5234286			156.7815607					
155		L2= Areas 3,4			17.8329166			304.4959518					
156		Sr= Fresno, Madera			31.9684			468.3626					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 3									4.027627725		
159		L2= Areas 3,4									6.605602158		
160		Sr= Fresno, Madera									10.6469		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 3									3.749205461		
163		L2= Areas 3,4									6.148969412		
164		Sr= Fresno, Madera									9.9109		
165		R= SJV									27.083		
210													
211	**2010-2011 Rollback Protection**												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	1.1	0.6	0.7	0.4	0.5	2.0	4.2	0.9		2.4
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.7	0.4	0.2	0.3	0.3	1.2	2.6	0.6		0.5
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.1	0.1	0.6	1.3	0.3		0.3
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.9	0.1	0.1	0.0	0.0	0.0	0.2	0.4	0.1		0.2
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.7		1.6	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	49.67	21.4	2.1	1.2	1.0	1.6	0.9	5.5	9.6	2.9	0.0	3.4
218	**2010-2011 Rollback Projection with additional controls**												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	10.2	1.0	0.6	0.7	0.4	0.5	1.7	4.0	0.9		2.1
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.2	0.6	0.4	0.2	0.2	0.3	1.0	2.5	0.5		0.4
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.5	0.3	0.2	0.1	0.1	0.1	0.5	1.3	0.3		0.3
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.7	0.1	0.1	0.0	0.0	0.0	0.2	0.4	0.1		0.1
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.7		1.6	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	44.88	18.6	2.1	1.2	1.0	1.4	0.9	4.8	9.2	2.7	0.0	3.0
225													

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Kern - Bakersfield Golden state, Annual, Design Value = 57**	**General Note**	**Geologic and Construction**	**Mobile Exhaust**		**Tire and Brake Wear**	**Organic Carbon**		**Vegetative Burning**	**Ammonium Nitrate Including associated water**	**Ammonium Sulfate**	**Marine**	**Unassigned**
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any
3	LINE 1	57.00	26.70	3.50		1.10	1.89		4.41	14.90	3.00	0.00	1.4
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions		see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic.	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	7.89	4.0	0.0		0.0	0.6		1.3	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	49.11	22.7	3.6		1.1	1.3		3.1	13.9	2.0	0.0	1.4
8	Line4 Local Contribution PM2.5-PM10 Area of influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 30%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	29.60	15.9	1.8		0.8	0.7		1.5	7.0	1.0		1.0
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	10.95	3.4	1.1		0.2	0.40		0.9	4.2	0.8		0.2
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	6.11	2.3	0.5		0.1	0.20		0.5	2.09	0.30		0.1
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.46	1.1	0.2		0.1	0.07		0.2	0.70	0.10		0.1
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	1999 Emissions Inventory	(area of influence emissions inventory, each on a separate line for automated calculations)											
18	PM10	L1= 12	11.03358816	1.86013502		0.32245184	3.544494187		2.22460778				19.25500973
19		L2= Kern	33.4683	2.5679		0.385975235	7.902		3.7496				47.694
20		Sr= Kern	33.4683	2.5679		0.385975235	7.902		3.7496				47.694
21		R= SJV	230.9463	14.9086		1.92	24.7498		34.9152				305.5217
22	NOx	L1= 12								102.0700607			
23		L2= Kern								156.4546			
24		Sr= Kern								156.4546			
25		R= SJV								565.1907			
26	TOG	L1= 12			26.686689			88.47924915					
27		L2= Kern			36.6317			181.1592					
28		Sr= Kern			36.6317			181.1592					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= 12									3.063829679		
31		L2= Kern									11.0342		
32		Sr= Kern									11.0342		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Kern - Bakersfield Golden state, Annual, Design Value = 57	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
1													
133	**2010-2011 Emissions Inventory**												
134	PM10 2010 EI without new controls	L1= 12	12.56590734	1.70808265		0.466797727	3.929400598		2.33341034				21.39238808
135		L2= Kern	38.1163	2.3033		0.558757433	8.7601		3.8441				53.0238
136		Sr= Kern	38.1163	2.3033		0.558757433	8.7601		3.8441				53.0238
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= 12	9.359180014	1.64412054		0.466797727	3.790348055		1.772532331				16.95732469
139		L2= Kern	28.3893	2.21704894		0.558757433	8.4501		2.9201				41.97654894
140		Sr= Kern	28.3893	2.21704894		0.558757433	8.4501		2.9201				41.97654894
141		R= SJV	196.7944	12.8523		2.63	26.3051		29.2898				265.2426
142	NOx 2010 EI without new controls	L1= 12								76.55788003			
143		L2= Kern								119.9136			
144		Sr= Kern								119.9136			
145		R= SJV								401.6368			
146	NOx 2010 EI with new controls	L1= 12								67.5854568			
147		L2= Kern								105.8599772			
148		Sr= Kern								105.8599772			
149		R= SJV								363.7858			
150	TOG 2010 EI without new controls	L1= 12			15.771761			96.34351451					
151		L2= Kern			22.3177			197.2611					
152		Sr= Kern			22.3177			197.2611					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= 12			15.771761			87.59420854					
155		L2= Kern			22.3177			179.3471					
156		Sr= Kern			22.3177			179.3471					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= 12									3.281946052		
159		L2= Kern									12.3121		
160		Sr= Kern									12.3121		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= 12									2.000579374		
163		L2= Kern									7.5051		
164		Sr= Kern									7.5051		
165		R= SJV									27.083		
210													
211	**2010-2011 Rollback Projection**												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	18.1	0.8	0.5	1.1	0.4	0.4	1.6	5.8	1.1		1.1
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	3.9	0.5	0.3	0.2	0.2	0.2	0.9	3.5	0.7		0.2
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	2.6	0.2	0.2	0.2	0.1	0.1	0.5	1.8	0.3		0.2
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	1.3	0.1	0.0	0.1	0.0	0.0	0.2	0.6	0.1		0.1
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.3	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	58.03	29.8	1.6	1.1	1.6	1.3	0.7	4.5	12.6	3.2	0.0	1.6
218	**2010-2011 Rollback Projection with additional controls**												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	13.5	0.8	0.5	1.1	0.4	0.3	1.2	5.4	0.7		0.9
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.9	0.5	0.3	0.2	0.2	0.2	0.7	3.3	0.4		0.2
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.9	0.2	0.2	0.2	0.1	0.1	0.4	1.6	0.2		0.1
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	1.0	0.1	0.0	0.1	0.0	0.0	0.1	0.5	0.1		0.1
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.3	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	48.60	23.3	1.6	1.1	1.6	1.3	0.7	3.8	11.8	2.4	0.0	1.2
225													

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Kings - Hanford , Annual, Design Value = 53**	**General Note**	**Geologic and Construction**	**Mobile Exhaust**		**Tire and Brake Wear**	**Organic Carbon**		**Vegetative Burning**	**Ammonium Nitrate Including associated water**	**Ammonium Sulfate**	**Marine**	**Unassigned**
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any
3	LINE 1	53.00	23.20	4.00		0.50	1.98		4.62	15.70	3.00	0.00	0
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions = 30%		see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic.	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	7.98	4.0	0.0		0.0	0.6		1.4	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	45.02	19.2	4.0		0.5	1.4		3.2	14.7	2.0	0.0	0.0
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	26.45	13.4	2.0		0.4	0.7		1.6	7.4	1.0		0.0
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	10.55	2.9	1.2		0.1	0.42		1.0	4.4	0.6		0.0
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	5.77	1.9	0.6		0.1	0.21		0.5	2.21	0.30		0.0
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.25	1.0	0.2		0.0	0.07		0.2	0.74	0.10		0.0
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	**1999 Emissions Inventory**	(area of influence emissions inventory, each on a separate line for automated calculations)											
18	PM10	L1= Area 5	10.62726401	0.34354204		0.054081039	0.305464261		1.704288207				13.44158539
19		L2= Areas 5,6,7,8	39.31045835	1.76730805		0.270093113	3.393649713		2.96197731				45.81837627
20		Sr= Tulare, Kings	49.3218	2.5364		0.294088989	4.5008		4.5848				60.9543
21		R= SJV	230.9463	14.9086		1.92	24.7498		34.9152				305.5217
22	NOx	L1= Area 5								20.44159256			
23		L2= Areas 5,6,7,8								72.19531862			
24		Sr= Tulare, Kings								77.774			
25		R= SJV								565.1907			
26	TOG	L1= Area 5			5.87213601			91.01532476					
27		L2= Areas 5,6,7,8			26.9341378			277.6758466					
28		Sr= Tulare, Kings			34.3569			249.4981					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 5									2.195643579		
31		L2= Areas 5,6,7,8									3.154201496		
32		Sr= Tulare, Kings									1.7691		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Kings - Hanford , Annual, Design Value = 53**	**General Note**	**Geologic and Construction**	**Mobile Exhaust**		**Tire and Brake Wear**	**Organic Carbon**		**Vegetative Burning**	**Ammonium Nitrate including associated water**	**Ammonium Sulfate**	**Marine**	**Unassigned**
133	**2010-2011 Emissions inventory**												
134	PM10 2010 EI without new controls	L1= Area 5	11.71676419	0.31680007		0.078620969	0.348794276		1.692896835				14.5826762
135		L2= Areas 5,6,7,8	43.74474024	1.5914437		0.402170266	4.202372951		2.997549258				50.95666471
136		Sr= Tulare, Kings	54.7212	2.2327		0.438789405	5.5343		4.5763				67.0645
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1796				331.6046
138	PM10 2010 EI with new controls	L1= Area 5	9.60813547	0.30493694		0.078620969	0.320748552		1.637533764				11.76737321
139		L2= Areas 5,6,7,8	35.87213872	1.53184933		0.402170266	3.864470062		2.296179391				40.43037948
140		Sr= Tulare, Kings	44.8732	2.14909268		0.438789405	5.0893		3.8233				53.88789268
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2898				265.2426
142	NOx 2010 EI without new controls	L1= Area 5								13.78371425			
143		L2= Areas 5,6,7,8								49.36328821			
144		Sr= Tulare, Kings								52.7948			
145		R= SJV								401.6368			
146	NOx 2010 EI with new controls	L1= Area 5								12.44632963			
147		L2= Areas 5,6,7,8								44.57374446			
148		Sr= Tulare, Kings								47.6723089			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 5			3.40459935			112.9643685					
151		L2= Areas 5,6,7,8			14.8601553			354.3705663					
152		Sr= Tulare, Kings			20.4143			322.0508					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 5			3.40459935			112.7861796					
155		L2= Areas 5,6,7,8			14.8601553			353.8115854					
156		Sr= Tulare, Kings			20.4143			321.5428					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 5									2.569842275		
159		L2= Areas 5,6,7,8									3.49721152		
160		Sr= Tulare, Kings									1.7466		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 5									2.537472797		
163		L2= Areas 5,6,7,8									3.453160991		
164		Sr= Tulare, Kings									1.7246		
165		R= SJV									27.083		
210													
211	**2010-2011 Rollback Projection**												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	14.8	0.9	0.6	0.5	0.4	0.4	1.6	5.8	1.2		0.0
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	3.2	0.5	0.3	0.1	0.3	0.3	1.0	3.5	0.7		0.0
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	2.1	0.3	0.2	0.1	0.1	0.1	0.5	1.7	0.3		0.0
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	1.1	0.1	0.1	0.0	0.0	0.0	0.2	0.6	0.1		0.0
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.4	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	51.61	25.2	1.8	1.1	0.7	1.4	0.9	4.6	12.6	3.2	0.0	0.0
218	**2010-2011 Rollback Projection with additional controls**												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	0.9	0.6	0.5	0.4	0.4	1.6	5.4	1.2		0.0
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.5	0.3	0.1	0.2	0.3	0.8	3.3	0.7		0.0
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.1	0.1	0.4	1.6	0.3		0.0
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.9	0.1	0.1	0.0	0.0	0.0	0.1	0.8	0.1		0.0
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.4	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	46.56	21.4	1.7	1.1	0.7	1.3	0.9	4.2	11.9	3.2	0.0	0.0
225													

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Tulare - Visalia Church St., Annual, Design Value =53	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any
3	LINE 1	53.00	21.70	4.00		0.50	2.01		4.69	15.90	3.10	0.00	1.1
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations Includes biogenic emissions =30%		see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic	see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mess
5	LINE 2	8.01	4.0	0.0		0.0	0.6		1.4	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	44.99	17.7	4.0		0.5	1.4		3.3	14.9	2.1	0.0	1.1
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	26.36	12.4	2.0		0.4	0.7		1.6	7.5	1.1		0.8
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	10.60	2.7	1.2		0.1	0.42		1.0	4.5	0.6		0.2
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	5.78	1.8	0.8		0.1	0.21		0.5	2.24	0.32		0.1
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.25	0.9	0.2		0.0	0.07		0.2	0.75	0.11		0.1
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	1999 Emissions Inventory	(area of influence emissions inventory, each on a separate line for automated calculations)											
18	PM10	L1= Area 7	10.56623993	0.89425904		0.150936689	1.811192465		1.289762432				19.6725921
19		L2= Areas 5,6,7,8	39.31045835	1.76730805		0.270093113	3.393649713		2.96197731				45.81837827
20		Sr= Kings, Tulare	49.3218	2.5364		0.294086989	4.5008		4.5846				80.9543
21		R= SJV	230.9463	14.9086		1.92	24.7498		34.9152				305.5217
22	NOx	L1= Area 7								31.60341191			
23		L2= Areas 5,6,7,8								72.19531862			
24		Sr= Kings, Tulare								77.774			
25		R= SJV								565.1907			
26	TOG	L1= Area 7			14.0088756			110.9205375					
27		L2= Areas 5,6,7,8			26.9341378			277.6758466					
28		Sr= Kings, Tulare			34.3569			249.4981					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 7									0.61608148		
31		L2= Areas 5,6,7,8									3.154201496		
32		Sr= Kings, Tulare									1.7691		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Tulare - Visalia Church St., Annual, Design Value =53**	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned
133	2010-2011 Emissions Inventory												
134	PM10 2010 EI without new controls	L1= Area 7	11.92128958	0.81186303		0.226265922	2.327694829		1.306268216				17.21351538
135		L2= Areas 5,6,7,8	43.74474024	1.5914437		0.402170266	4.202372951		2.997549258				50.95666471
136		Sr= Kings, Tulare	54.7212	2.2327		0.438789405	5.5343		4.5763				67.0645
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= Area 7	9.77585308	0.78146141		0.226265922	2.140530382		1.000626145				14.33073764
139		L2= Areas 5,6,7,8	35.87213872	1.53184933		0.402170266	3.864470062		2.296179391				40.43037948
140		Sr= Kings, Tulare	44.8732	2.14909268		0.438789405	5.0693		3.8233				53.88789268
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2898				265.2426
142	NOx 2010 EI without new controls	L1= Area 7								21.71305361			
143		L2= Areas 5,6,7,8								49.36328821			
144		Sr= Kings, Tulare								52.7948			
145		R= SJV								401.6368			
146	NOx 2010 EI with new controls	L1= Area 7								19.60631348			
147		L2= Areas 5,6,7,8								44.57374446			
148		Sr= Kings, Tulare								47.6723089			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 7			7.48994723			143.4957947					
151		L2= Areas 5,6,7,8			14.8601553			354.3705663					
152		Sr= Kings, Tulare			20.4143			322.0508					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 7			7.48994723			143.2694457					
155		L2= Areas 5,6,7,8			14.8601553			353.8115854					
156		Sr= Kings, Tulare			20.4143			321.5428					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 7									0.592211336		
159		L2= Areas 5,6,7,8									3.49721152		
160		Sr= Kings, Tulare									1.7466		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 7									0.584751901		
163		L2= Areas 5,6,7,8									3.453160991		
164		Sr= Kings, Tulare									1.7246		
165		R= SJV									27.083		
210													
211	**2010-2011 Rollback Projection**												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	14.0	0.9	0.5	0.5	0.5	0.5	1.7	5.9	1.0		0.7
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	3.0	0.5	0.3	0.1	0.3	0.3	1.0	3.5	0.7		0.2
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	2.0	0.3	0.2	0.1	0.1	0.1	0.5	1.8	0.3		0.1
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	1.0	0.1	0.1	0.0	0.0	0.0	0.2	0.6	0.1		0.1
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.4	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	51.56	23.9	1.8	1.1	0.7	1.5	0.9	4.7	12.8	3.1	0.0	1.0
218	**2010-2011 Rollback Projection with additional controls**												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	11.5	0.9	0.5	0.5	0.4	0.5	1.3	5.6	1.0		0.6
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.4	0.5	0.3	0.1	0.2	0.3	0.8	3.3	0.7		0.1
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.6	0.3	0.2	0.1	0.1	0.1	0.4	1.7	0.3		0.1
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.8	0.1	0.1	0.0	0.0	0.0	0.1	0.6	0.1		0.0
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.6		1.4	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	46.23	20.3	1.7	1.1	0.7	1.4	0.9	4.0	12.1	3.1	0.0	0.9
225													

ANNUAL Average, based on CMB results for February to December 2000 plus the Jan 2001 Episode

				Design	Sum of	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological		Geological	
SITEID	CONC	UCONC	PCMASS	Value	species			Mass		Mass		Mass		Mass		Mass		Profile	Unassigned
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	49.5	3.2	98.4	50.0	46.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3	FDFSDANN	3.1
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

This analysis provides a seasonally adjusted annual average, using the January episode to reflect the dominant winter chemistry.

Bakersfield Golden State Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
BGS	1/1/01	205	10.3	93.6	1.0	0.9	23.3	6.3	6.7	4.7	1.3	1.7	7.0	0.7	95.4	7.8	58.2	9.6
BGS	Feb	24.4	1.9	96.4	1.0	0.7	4.1	2.3	1.7	1.3	0.6	0.6	1.2	0.1	5.1	0.6	10.9	3.2
BGS	Mar	22.2	2.1	107.7	1.0	1.0	2.1	2.2	2.1	1.4	0.6	0.6	1.9	0.2	5.5	0.6	11.7	3.1
BGS	Apr	31.5	2.4	107.8	1.0	0.4	6.3	3.2	2.1	1.7	0.5	0.7	3.0	0.3	4.9	0.6	17.3	4.6
BGS	May*	34.6	2.5	118.5	1.0	0.5	0.3	0.4	5.3	2.6			3.1	0.3	4.5	0.5	27.8	5.7
BGS	Jun*	41.3	2.7	102.7	1.0	0.6	0.9	0.4	5.1	2.6			3.8	0.3	3.1	0.4	29.4	6.0
BGS	Jul*	37.0	2.6	101.3	0.9	2.2	7.1	1.1	0.2	1.4	2.4	1.4	2.1	0.2	2.2	0.3	23.4	5.9
BGS	Aug*	43.5	2.6	97.8	1.0	1.2	4.1	0.8	2.2	1.9	0.5	1.4	2.5	0.3	2.9	0.4	30.2	6.5
BGS	Sep*	78.6	4.7	98.3	0.9	1.2	3.5	1.4	4.5	3.3	0.8	2.7	3.0	0.4	3.6	0.4	61.9	12.5
BGS	Oct*	36.1	2.8	83.9	1.0	1.0	3.5	0.7	1.6	1.3	1.4	1.0	1.9	0.2	5.2	0.6	16.7	4.3
BGS	Nov	48.4	2.9	86.3	1.0	0.4	7.9	3.4	4.6	2.7	0.6	0.7	2.2	0.2	14.0	1.2	12.3	3.1
BGS	Dec	90.2	5.1	87.4	1.0	0.6	12.5	5.1	7.0	4.2	2.1	1.2	4.3	0.4	32.2	2.7	20.9	5.4
Min		22.2	1.9	83.9	0.9	0.4	0.3	0.4	0.2	1.3	0.5	0.6	1.2	0.1	2.2	0.3	10.9	3.1
Avg		57.7	3.6	98.5	1.0	0.9	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8
Max		205.0	10.3	118.5	1.0	2.2	23.3	6.3	7.0	4.7	2.4	2.7	7.0	0.7	95.4	7.8	61.9	12.5

Fresno Drummond Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.3446	0.32946	2.1	1.4			2.3269	0.22637	2.4774	0.32112	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6
Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Hanford Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
HAN	Feb	20.0	1.8	105.0	0.9	0.5	5.0	1.7	1.4	1.0	0.0	0.3	1.4	0.2	8.6	0.9	4.6	1.3
HAN	Mar	21.4	2.0	100.3	0.9	0.5	4.0	1.8	1.6	1.0	0.2	0.3	1.8	0.2	7.1	0.7	6.8	1.8
HAN	Apr*	22.3	2.1	120.6	1.0	0.3	0.4	0.3	3.2	1.6			2.2	0.2	5.0	0.5	16.1	2.8
HAN	May*	24.4	2.1	107.3	1.0	0.3	1.1673	0.35652	2.4	1.4			2.4472	0.22382	3.7747	0.44049	16.4	2.79498
HAN	Jun*	31.3	2.5	107.9	1.0	0.4	3.2	0.5	2.4	1.6	0.2	0.6	3.8	0.3	4.1	0.5	20.1	4.1
HAN	Jul*	38.7	2.6	107.9	0.9	0.7	3.6	0.6	2.7	1.6	0.2	0.7	3.4	0.3	5.6	0.6	26.3	4.7
HAN	Aug*	43.3	2.6	103.7	0.9	0.5	4.2	0.6	1.9	1.5	0.3	0.8	2.0	0.2	2.7	0.4	33.8	5.7
HAN	Sep*	70.5	4.0	105.3	0.9	0.5	2.5	0.8	4.3	2.7	0.5	1.2	3.1	0.4	5.0	0.7	58.8	8.8
HAN	Oct*	51.8	3.4	90.9	1.0	0.3	1.0	0.5	3.7	2.2	0.2	0.8	2.4	0.3	7.6	0.8	32.2	5.8
HAN	Nov	46.4	2.8	107.6	1.0	0.4	13.5	3.6	4.8	2.9	1.0	0.5	2.4	0.3	17.7	1.5	10.5	2.7
HAN	Dec	62.8	3.6	89.4	1.0	0.5	12.4	3.4	4.4	2.5	0.9	0.5	3.7	0.4	23.9	2.1	10.7	2.8
Min		20.0	1.8	89.4	0.9	0.3	0.4	0.3	1.4	1.0	0.0	0.3	1.4	0.2	2.7	0.4	4.6	1.3
Avg		51.5	3.3	104.1	1.0	0.4	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2
Max		185.0	9.6	120.6	1.0	0.7	27.6	9.7	14.7	7.8	1.7	1.2	7.2	0.7	96.9	7.9	58.8	8.8

Visalia Church Street Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
VCS	Feb	25.0	2.1	99.8	1.0	0.5	5.3	2.1	2.0	1.3	0.0	0.5	1.1	0.1	9.0	1.0	7.6	1.9
VCS	Mar	27.5	2.2	102.9	1.0	1.0	4.8	2.2	2.9	1.7	0.1	0.5	2.1	0.2	10.0	0.9	8.4	1.9
VCS	Apr	26.2	2.2	115.3	1.0	0.7	5.6	2.8	1.7	1.6	0.6	0.6	2.8	0.3	5.9	0.6	13.7	2.9
VCS	May**	29.1	2.3	112.8	1.0	0.7	5.4	3.6	1.4	1.6			2.8	0.3	3.8	0.5	19.4	3.2
VCS	Jun*	42.0	2.7	106.1	1.0	0.7	0.8	0.4	4.9	2.7			5.4	0.5	5.2	0.6	28.2	3.9
VCS	Jul*	34.7	2.5	107.8	0.9	1.4	3.7	0.6	1.8	1.7	0.5	1.1	2.9	0.3	4.9	0.6	23.7	3.8
VCS	Aug*	44.9	2.7	98.5	0.9	1.3	3.6	0.7	1.4	1.6	0.3	1.4	2.3	0.3	4.2	0.5	32.4	4.9
VCS	Sep*	59.1	3.5	84.4	0.9	1.3	3.4	0.8	1.9	1.9	0.7	1.6	3.0	0.3	4.8	0.6	36.0	5.7
VCS	Oct*	53.7	3.5	83.6	1.0	0.6	1.6	0.7	4.4	2.6	0.0	1.4	2.4	0.3	9.8	1.0	26.7	4.5
VCS	Nov	37.3	2.5	94.1	1.0	0.6	5.8	3.1	6.1	2.9			1.8	0.2	10.9	1.0	10.5	2.1
VCS	Dec	65.0	3.8	87.5	1.0	0.9	12.7	3.6	4.6	2.7	0.6	0.7	3.2	0.3	24.8	2.1	11.2	2.6
Min		25.0	2.1	83.6	0.9	0.4	0.8	0.4	1.4	1.3	0.0	0.5	1.1	0.1	3.8	0.5	7.6	1.9
Avg		52.5	3.3	99.6	1.0	0.9	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8
Max		185.0	9.6	115.3	1.0	1.4	27.6	9.7	14.7	7.8	1.7	1.6	7.2	0.7	96.9	7.9	42.4	7.7

NOTES: Burning profile was switched from wood burning to agricultural burning based on ARB monthly emissions inventory estimates.
Asterisk * denotes AgBWheat profile used; ** denotes WBAlmond (some AgBWheat/WBAlmond used in April/May)

Source Profiles

	Jan-May and Nov-Dec	June-Oct	
Burning	22 WBOakEuc	27 AgBWheat*	
Sulfate	57 Amsul	57 Amsul	
Nitrate	60 Amnit	60 Amnit	
Motor Vehicle	65 CAMV	65 CAMV	
Tire/Brake	67 TireBrke	67 TireBrke	Note: (not used if run came out negative)
Geological	92 FDHANANN	92 FDHANANN	
	93 FDFREANN	93 FDFREANN	
	94 FDVCSANN	94 FDVCSANN	
	95 FDKERANN	95 FDKERANN	

DATE		Rollback default percentage, adjust by episode properties					
			Local	PM2.5	Sub regional	Regional	Total
		Default 2.5-10	70	15	10	5	100
		Default 2.5	50	30	15	5	100
		Note: distribution of anthropogenic contribution after subtraction of background					
	Mapping of local, PM2.5-local, and sub-regional based on trajectory analysis						
			Areas used				
24-hr date	Site Name	Value	Local	PM2.5	Sub regional	Regional	# of dates
11/6/97	Corcoran-Patterson Avenue	199					
12/31/98	Bakersfield-Golden State Highway	159					
	Visalia-N Church Street	160					
1/12/99	Oildale-3311 Manor Street	156	12	12,13	Kern	SJV	1
10/21/99	Corcoran-Patterson Avenue	174	6	5,6,7,8	Kings-Tulare	SJV	2
	Fresno-Drummond Street	162	3	3,4	Fresno-Madera	SJV	3
	Turlock-S Minaret Street	157	1	1,2	Stanislaus-Merced	SJV	4
11/14/99	Bakersfield-Golden State Highway	183	12	6,7,8,10,12	Kings-Tulare-Kern	SJV	5
12/11/99	Hanford-S Irwin Street	183					
12/17/99	Corcoran-Patterson Avenue	174	6	6,8	Kings-Tulare	SJV	6
12/23/99	Fresno-Drummond Street	168	3	3,4,7	Fresno-Tulare	SJV	7
	Hanford-S Irwin Street	156	5	5,6,8	Kings-Tulare	SJV	8
1/1/01	Bakersfield-5558 California Avenue	186	12	9,10,11,12	Kern	SJV	9
	Bakersfield-Golden State Highway	205	12	9,10,11,12	Kern	SJV	10
	Clovis-N Villa Avenue	155	3	3,4	Fresno-Madera	SJV	11
	Fresno-1st Street	193	3	3,4	Fresno-Madera	SJV	12
	Fresno-Drummond Street	186	3	3,4	Fresno-Madera	SJV	13
	Oildale-3311 Manor Street	158	12	9,10,11,12	Kern	SJV	14
1/4/01	Bakersfield-5558 California Avenue	190	12	10,12,13	Kern	SJV	15
	Bakersfield-Golden State Highway	208	12	10,12,13	Kern	SJV	16
	Fresno-Drummond Street	159	3	3,4	Fresno-Madera	SJV	17
	Oildale-3311 Manor Street	195	12	10,12,13	Kern	SJV	18
1/7/01	Bakersfield-5558 California Avenue	159	12	10,12	Kern	SJV	19
	Bakersfield-Golden State Highway	174	12	10,12	Kern	SJV	20
	Corcoran-Patterson Avenue	165	6	6,8,10,12	Kings-Tulare-Kern	SJV	21
	Hanford-S Irwin Street	185	5	5,6,7,8,10	Kings-Tulare-Kern	SJV	22
	Modesto-14th Street	158	1	1,2	St-Me-Ma- Fr-Tu	SJV	23
11/9/01	Hanford-S Irwin Street	155	5	5,7,8	Kings-Tulare	SJV	24

Annual	County	Value	Site	EPA Value
	Fresno	50	Fresno-Drummond	47-53
	Kings	53	Hanford, Irwin St	51
	Tulare	53	Visalia, Church Street	54
	Kern	57	Bakersfield-Golden	55

			Areas used			
Annual	County	Value	Local	PM2.5	Sub regional	Regional
	Fresno	50	3	3,4	Fresno-Madera	SJV
	Kings	53	5	5,6,7,8	Kings-Tulare	SJV
	Tulare	53	7	5,6,7,8	Tulare-Kings	SJV
	Kern	57	12	Kern	Kern	SJV

Appendix 2

District Review and Approval

PM10 Interpollutant Offset Ratio Analysis
for Fresno County

PM10

	Notes	Units	Estimate	Uncertainty		
"Vegetative Burning" Total	1	µg/m^3	7.48	2.43		"Annual based on Monthly" speciation worksheet cells G6 and H6
Industry Component (30%)	2	µg/m^3	2.24			"Fresno Annual" worksheet for speciated rollback analysis
Regional Background (20%)	3	µg/m^3	0.45			"
Industry minus Background		µg/m^3	1.80			"
County Contribution	4	µg/m^3	0.90			"
Organic Carbon PM10 Inventory - Fresno/Madera Co.	5	ton/day	5.63			" Required to use base year emissions that are related to the observed speciation
County Impact		µg/m^3 per ton	0.16	0.21		
				0.11		

Sulfate

	Notes	Units	Estimate	Uncertainty		
Ammonium Sulfate	6	µg/m^3	2.55	0.30		Annual based on Monthly, speciation worksheet cells M6 and N6
Regional Background	7	µg/m^3	1.00			"Fresno Annual" worksheet for speciated rollback analysis
Ammonium Sulfate minus Background		µg/m^3	1.55			"
County Contribution	8	µg/m^3	0.78			"
SOx Inventory - Fresno/Madera Counties	9	ton/day	9.08			" Required to use base year emissions that are related to the observed speciation
County Impact		µg/m^3 per ton	0.09	0.10		
				0.08		
Tons of SOx to Equal Effect of 1 Ton of PM10	10		1.866	2.21	0.35	
				1.43	-0.44	

1. Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Fresno - Drummond monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
4. Contribution from sources within Fresno & Madera Counties is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Fresno/Madera Counties that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Fresno - Drummond monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 µg/m^3.
8. Contribution from sources within Fresno County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. SOx inventory for Fresno/Madera Counties that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM10 County Impact divided by Ammonium Sulfate County Impact.

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Fresno - Drummond, Annual, Design value = 50**	**General Note**	**Geologic and Construction**	**Mobile Exhaust**		**Tire and Brake Wear**	**Organic Carbon**		**Vegetative Burning**	**Ammonium Nitrate including associated water**	**Ammonium Sulfate**	**Marine**	**Unassigned**
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any
3	LINE 1	50.00	19.50	4.60		0.70	2.25		5.25	12.00	2.80	0.00	3.1
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions.		see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic.	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	8.03	4.0	0.0		0.0	0.5		1.6	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	41.98	15.5	4.6		0.7	1.8		3.7	11.0	1.8	0.0	3.1
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence representative of large particle primary source area includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	24.85	10.9	2.3		0.5	0.9		1.8	5.5	0.8		2.2
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	9.70	2.3	1.4		0.1	0.54		1.1	3.3	0.5		0.5
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	5.33	1.6	0.7		0.1	0.27		0.6	1.65	0.24		0.3
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.10	0.8	0.2		0.0	0.09		0.2	0.55	0.08		0.2
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	**1999 Emissions Inventory**	(area of influence emissions inventory each on a separate line for automated calculations)											
18	PM10	L1= Area 3	7.236852297	1.55746265		0.270246847	1.54732371		2.946320228				15.67865018
19		L2= Areas 3,4	26.02510179	2.26760773		0.375484581	2.955506973		5.732736172				39.92145356
20		Sr= Fresno, Madera	74.4504	4.1236		0.511	5.6266		10.4843				94.6839
21		R= SJV	230.9463	14.9086		1.92	24.7498		34.9152				305.5217
22	NOx	L1= Area 3								53.21489079			
23		L2= Areas 3,4								86.61773631			
24		Sr= Fresno, Madera								144.7763			
25		R= SJV								565.19			
26	TOG	L1= Area 3			22.7065618			132.7691237					
27		L2= Areas 3,4			33.470797			257.8874576					
28		Sr= Fresno, Madera			58.2653			396.7168					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 3									3.438823609		
31		L2= Areas 3,4									5.665348981		
32		Sr= Fresno, Madera									9.0772		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Fresno - Drummond, Annual, Design value = 50**	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
133	**2010-2011 Emissions Inventory**												
134	PM10 2010 EI without new controls	L1= Area 3	8.129557687	1.44348665		0.367960339	1.747683078		3.262499732				17.31537711
135		L2= Areas 3 4	29.27328116	2.15521975		0.543853899	3.283480261		6.107828372				44.15866903
136		Sr= Fresno, Madera	83.727	3.8288		0.746828157	6.2618		10.8882				104.7058
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= Area 3	6.809440309	1.38943472		0.367960339	1.5244012		2.650942087				15.31076142
139		L2= Areas 3 4	24.51972576	2.07451381		0.543853899	2.883986791		4.982912068				37.05429637
140		Sr= Fresno, Madera	70.131	3.68542395		0.746828157	5.4618		8.8472				84.47342395
141		R= SJV	205.8304	12.6523		2.63	26.3051		29.2898				265.2426
142	NOx 2010 EI without new controls	L1= Area 3								34.57241458			
143		L2= Areas 3 4								62.07171354			
144		Sr= Fresno, Madera								103.4162			
145		R= SJV								401.6368			
146	NOx 2010 EI with new controls	L1= Area 3								31.73589191			
147		L2= Areas 3 4								56.97898788			
148		Sr= Fresno, Madera								94.93133136			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 3			11.5234286			156.7815607					
151		L2= Areas 3 4			17.8329166			304.4959518					
152		Sr= Fresno, Madera			31.9684			468.3626					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 3			11.5234286			156.7815607					
155		L2= Areas 3 4			17.8329166			304.4959518					
156		Sr= Fresno, Madera			31.9684			468.3626					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 3									4.027627725		
159		L2= Areas 3 4									6.605602158		
160		Sr= Fresno, Madera									10.6469		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 3									3.749205461		
163		L2= Areas 3 4									6.148969412		
164		Sr= Fresno, Madera									9.9109		
165		R= SJV									27.083		
210													
211	**2010-2011 Rollback Protection**												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	1.1	0.6	0.7	0.5	0.5	2.0	4.2	0.9		2.4
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.7	0.4	0.2	0.3	0.3	1.2	2.6	0.6		0.5
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.2	0.2	0.6	1.3	0.3		0.3
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.9	0.1	0.1	0.0	0.1	0.1	0.2	0.4	0.1		0.2
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.5		1.6	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	49.71	21.4	2.1	1.2	1.0	1.5	1.1	5.5	9.6	2.9	0.0	3.4
218	**2010-2011 Rollback Projection with additional controls**												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	10.2	1.0	0.6	0.7	0.4	0.5	1.7	4.0	0.9		2.1
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.2	0.6	0.4	0.2	0.3	0.3	1.0	2.5	0.5		0.4
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.5	0.3	0.2	0.1	0.1	0.2	0.5	1.3	0.3		0.3
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.7	0.1	0.1	0.0	0.0	0.1	0.2	0.4	0.1		0.1
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.5		1.6	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	44.90	18.8	2.1	1.2	1.0	1.3	1.1	4.8	9.2	2.7	0.0	3.0
225													

ANNUAL Average, based on CMB results for February to December 2000 plus the Jan 2001 Episode

				Design	Sum of	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological		Geological	
SITEID	CONC	UCONC	PCMASS	Value	species			Mass		Mass		Mass		Mass		Mass		Profile	Unassigned
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	49.5	3.2	98.4	50.0	46.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3	FDFSDANN	3.1
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

This analysis provides a seasonally adjusted annual average, using the January episode to reflect the dominant winter chemistry.

Bakersfield Golden State Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
BGS	1/1/01	205	10.3	93.6	1.0	0.9	23.3	6.3	6.7	4.7	1.3	1.7	7.0	0.7	95.4	7.8	58.2	9.6
BGS	Feb	24.4	1.9	96.4	1.0	0.7	4.1	2.3	1.7	1.3	0.6	0.6	1.2	0.1	5.1	0.6	10.9	3.2
BGS	Mar	22.2	2.1	107.7	1.0	1.0	2.1	2.2	2.1	1.4	0.6	0.6	1.9	0.2	5.5	0.6	11.7	3.1
BGS	Apr	31.5	2.4	107.8	1.0	0.4	6.3	3.2	2.1	1.7	0.5	0.7	3.0	0.3	4.9	0.6	17.3	4.6
BGS	May*	34.6	2.5	118.5	1.0	0.5	0.3	0.4	5.3	2.6			3.1	0.3	4.5	0.5	27.8	5.7
BGS	Jun*	41.3	2.7	102.7	1.0	0.6	0.9	0.4	5.1	2.6			3.8	0.3	3.1	0.4	29.4	6.0
BGS	Jul*	37.0	2.6	101.3	0.9	2.2	7.1	1.1	0.2	1.4	2.4	1.4	2.1	0.2	2.2	0.3	23.4	5.9
BGS	Aug*	43.5	2.6	97.8	1.0	1.2	4.1	0.8	2.2	1.9	0.5	1.4	2.5	0.3	2.9	0.4	30.2	6.5
BGS	Sep*	78.6	4.7	98.3	0.9	1.2	3.5	1.4	4.5	3.3	0.8	2.7	3.0	0.4	3.6	0.4	61.9	12.5
BGS	Oct*	36.1	2.8	83.9	1.0	1.0	3.5	0.7	1.6	1.3	1.4	1.0	1.9	0.2	5.2	0.6	16.7	4.3
BGS	Nov	48.4	2.9	86.3	1.0	0.4	7.9	3.4	4.6	2.7	0.6	0.7	2.2	0.2	14.0	1.2	12.3	3.1
BGS	Dec	90.2	5.1	87.4	1.0	0.6	12.5	5.1	7.0	4.2	2.1	1.2	4.3	0.4	32.2	2.7	20.9	5.4
Min		22.2	1.9	83.9	0.9	0.4	0.3	0.4	0.2	1.3	0.5	0.6	1.2	0.1	2.2	0.3	10.9	3.1
Avg		57.7	3.6	98.5	1.0	0.9	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8
Max		205.0	10.3	118.5	1.0	2.2	23.3	6.3	7.0	4.7	2.4	2.7	7.0	0.7	95.4	7.8	61.9	12.5

Fresno Drummond Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.3446	0.32946	2.1	1.4			2.3269	0.22637	2.4774	0.32112	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6
Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Hanford Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
HAN	Feb	20.0	1.8	105.0	0.9	0.5	5.0	1.7	1.4	1.0	0.0	0.3	1.4	0.2	8.6	0.9	4.6	1.3
HAN	Mar	21.4	2.0	100.3	0.9	0.5	4.0	1.8	1.6	1.0	0.2	0.3	1.8	0.2	7.1	0.7	6.8	1.8
HAN	Apr*	22.3	2.1	120.6	1.0	0.3	0.4	0.3	3.2	1.6			2.2	0.2	5.0	0.5	16.1	2.8
HAN	May*	24.4	2.1	107.3	1.0	0.3	1.1673	0.35652	2.4	1.4			2.4472	0.22382	3.7747	0.44049	16.4	2.79498
HAN	Jun*	31.3	2.5	107.9	1.0	0.4	3.2	0.5	2.4	1.6	0.2	0.6	3.8	0.3	4.1	0.5	20.1	4.1
HAN	Jul*	38.7	2.6	107.9	0.9	0.7	3.6	0.6	2.7	1.6	0.2	0.7	3.4	0.3	5.6	0.6	26.3	4.7
HAN	Aug*	43.3	2.6	103.7	0.9	0.5	4.2	0.6	1.9	1.5	0.3	0.8	2.0	0.2	2.7	0.4	33.8	5.7
HAN	Sep*	70.5	4.0	105.3	0.9	0.5	2.5	0.8	4.3	2.7	0.5	1.2	3.1	0.4	5.0	0.7	58.8	8.8
HAN	Oct*	51.8	3.4	90.9	1.0	0.3	1.0	0.5	3.7	2.2	0.2	0.8	2.4	0.3	7.6	0.8	32.2	5.8
HAN	Nov	46.4	2.8	107.6	1.0	0.4	13.5	3.6	4.8	2.9	1.0	0.5	2.4	0.3	17.7	1.5	10.5	2.7
HAN	Dec	62.8	3.6	89.4	1.0	0.5	12.4	3.4	4.4	2.5	0.9	0.5	3.7	0.4	23.9	2.1	10.7	2.8
Min		20.0	1.8	89.4	0.9	0.3	0.4	0.3	1.4	1.0	0.0	0.3	1.4	0.2	2.7	0.4	4.6	1.3
Avg		51.5	3.3	104.1	1.0	0.4	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2
Max		185.0	9.6	120.6	1.0	0.7	27.6	9.7	14.7	7.8	1.7	1.2	7.2	0.7	96.9	7.9	58.8	8.8

Visalia Church Street Monthly

							Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
VCS	Feb	25.0	2.1	99.8	1.0	0.5	5.3	2.1	2.0	1.3	0.0	0.5	1.1	0.1	9.0	1.0	7.6	1.9
VCS	Mar	27.5	2.2	102.9	1.0	1.0	4.8	2.2	2.9	1.7	0.1	0.5	2.1	0.2	10.0	0.9	8.4	1.9
VCS	Apr	26.2	2.2	115.3	1.0	0.7	5.6	2.8	1.7	1.6	0.6	0.6	2.8	0.3	5.9	0.6	13.7	2.9
VCS	May**	29.1	2.3	112.8	1.0	0.7	5.4	3.6	1.4	1.6			2.8	0.3	3.8	0.5	19.4	3.2
VCS	Jun*	42.0	2.7	106.1	1.0	0.7	0.8	0.4	4.9	2.7			5.4	0.5	5.2	0.6	28.2	3.9
VCS	Jul*	34.7	2.5	107.8	0.9	1.4	3.7	0.6	1.8	1.7	0.5	1.1	2.9	0.3	4.9	0.6	23.7	3.8
VCS	Aug*	44.9	2.7	98.5	0.9	1.3	3.6	0.7	1.4	1.6	0.3	1.4	2.3	0.3	4.2	0.5	32.4	4.9
VCS	Sep*	59.1	3.5	84.4	0.9	1.3	3.4	0.8	1.9	1.9	0.7	1.6	3.0	0.3	4.8	0.6	36.0	5.7
VCS	Oct*	53.7	3.5	83.6	1.0	0.6	1.6	0.7	4.4	2.6	0.0	1.4	2.4	0.3	9.8	1.0	26.7	4.5
VCS	Nov	37.3	2.5	94.1	1.0	0.6	5.8	3.1	6.1	2.9			1.8	0.2	10.9	1.0	10.5	2.1
VCS	Dec	65.0	3.8	87.5	1.0	0.9	12.7	3.6	4.6	2.7	0.6	0.7	3.2	0.3	24.8	2.1	11.2	2.6
Min		25.0	2.1	83.6	0.9	0.4	0.8	0.4	1.4	1.3	0.0	0.5	1.1	0.1	3.8	0.5	7.6	1.9
Avg		52.5	3.3	99.6	1.0	0.9	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8
Max		185.0	9.6	115.3	1.0	1.4	27.6	9.7	14.7	7.8	1.7	1.6	7.2	0.7	96.9	7.9	42.4	7.7

NOTES: Burning profile was switched from wood burning to agricultural burning based on ARB monthly emissions inventory estimates.
Asterisk * denotes AgBWheat profile used; ** denotes WBAlmond (some AgBWheat/WBAlmond used in April/May)

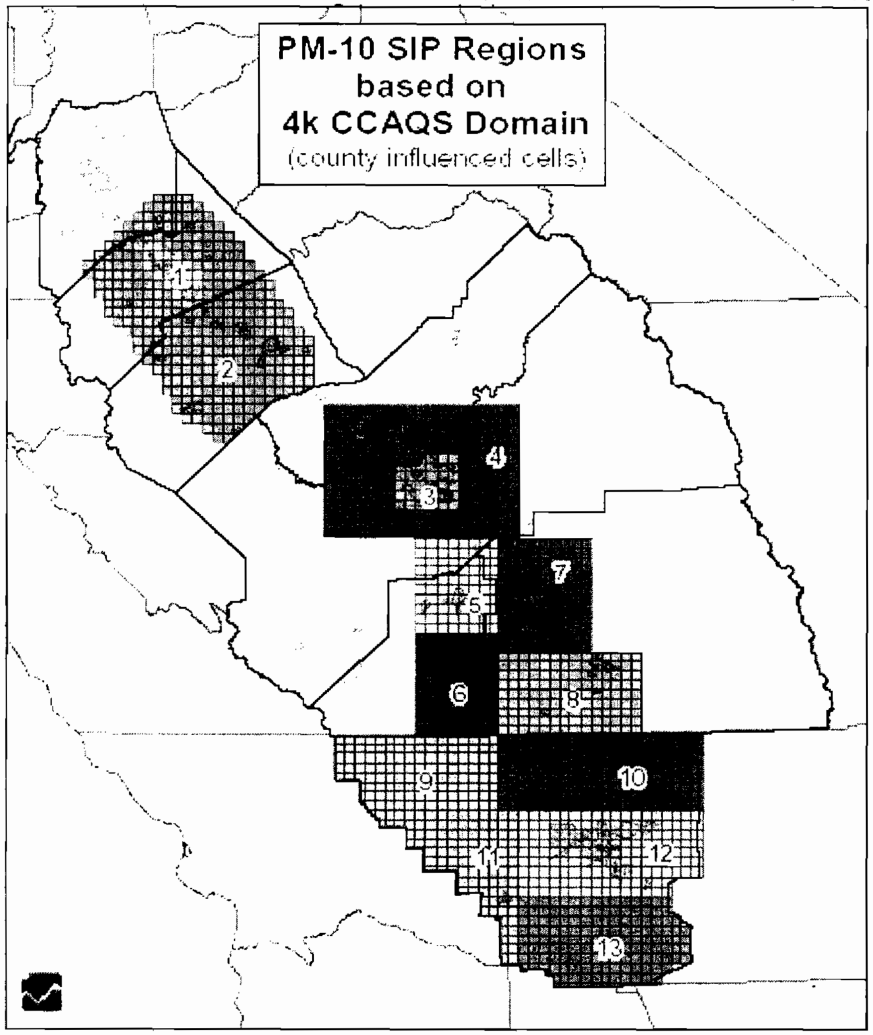
Source Profiles

	Jan-May and Nov-Dec	June-Oct	
Burning	22 WBOakEuc	27 AgBWheat*	
Sulfate	57 Amsul	57 Amsul	
Nitrate	60 Amnit	60 Amnit	
Motor Vehicle	65 CAMV	65 CAMV	
Tire/Brake	67 TireBrke	67 TireBrke	Note: (not used if run came out negative)
Geological	92 FDHANANN	92 FDHANANN	
	93 FDFREANN	93 FDFREANN	
	94 FDVCSANN	94 FDVCSANN	
	95 FDKERANN	95 FDKERANN	

		Rollback default percentage, adjust by episode properties					
			Local	PM2.5	Sub regional	Regional	Total
		Default 2.5-10	70	15	10	5	100
		Default 2.5	50	30	15	5	100
		Note: distribution of anthropogenic contribution after subtraction of background					
	Mapping of local, PM2.5-local, and sub-regional based on trajectory analysis						
					Areas used		
24-hr date	**Site Name**	**Value**	**Local**	**PM2.5**	**Sub regional**	**Regional**	**# of dates**
11/6/97	Corcoran-Patterson Avenue	199					
12/31/98	Bakersfield-Golden State Highway	159					
	Visalia-N Church Street	160					
1/12/99	Oildale-3311 Manor Street	156	12	12,13	Kern	SJV	1
10/21/99	Corcoran-Patterson Avenue	174	6	5,6,7,8	Kings-Tulare	SJV	2
	Fresno-Drummond Street	162	3	3,4	Fresno-Madera	SJV	3
	Turlock-S Minaret Street	157	1	1,2	Stanislaus-Merced	SJV	4
11/14/99	Bakersfield-Golden State Highway	183	12	6,7,8,10,12	Kings-Tulare-Kern	SJV	5
12/11/99	Hanford-S Irwin Street	183					
12/17/99	Corcoran-Patterson Avenue	174	6	6,8	Kings-Tulare	SJV	6
12/23/99	Fresno-Drummond Street	168	3	3,4,7	Fresno-Tulare	SJV	7
	Hanford-S Irwin Street	156	5	5,6,8	Kings-Tulare	SJV	8
1/1/01	Bakersfield-5558 California Avenue	186	12	9,10,11,12	Kern	SJV	9
	Bakersfield-Golden State Highway	205	12	9,10,11,12	Kern	SJV	10
	Clovis-N Villa Avenue	155	3	3,4	Fresno-Madera	SJV	11
	Fresno-1st Street	193	3	3,4	Fresno-Madera	SJV	12
	Fresno-Drummond Street	186	3	3,4	Fresno-Madera	SJV	13
	Oildale-3311 Manor Street	158	12	9,10,11,12	Kern	SJV	14
1/4/01	Bakersfield-5558 California Avenue	190	12	10,12,13	Kern	SJV	15
	Bakersfield-Golden State Highway	208	12	10,12,13	Kern	SJV	16
	Fresno-Drummond Street	159	3	3,4	Fresno-Madera	SJV	17
	Oildale-3311 Manor Street	195	12	10,12,13	Kern	SJV	18
1/7/01	Bakersfield-5558 California Avenue	159	12	10,12	Kern	SJV	19
	Bakersfield-Golden State Highway	174	12	10,12	Kern	SJV	20
	Corcoran-Patterson Avenue	165	6	6,8,10,12	Kings-Tulare-Kern	SJV	21
	Hanford-S Irwin Street	185	5	5,6,7,8,10	Kings-Tulare-Kern	SJV	22
	Modesto-14th Street	158	1	1,2	St-Me-Ma- Fr-Tu	SJV	23
11/9/01	Hanford-S Irwin Street	155	5	5,7,8	Kings-Tulare	SJV	24

AOI

Annual	County	Value	Local	PM2.5	Areas used Sub regional	Regional
	Kern	57	12	Kern	Kern	SJV



Notes for the Fresno/Madera Interpollutant Analysis

Combined emissions and inventories from Fresno and Madera Counties are used due to the evaluations of source interactions.
This relationship was established by analysis performed for the SJVAPCD PM10 SIP.

The interpollutant relationship established for Fresno County in this analysis would also be applicable to Madera County.

Tons of SOx to Equal Effect of 1 Ton of PM10	1.866	See SOxPM10 worksheet for calculations
Tons of NOx to Equal Effect of 1 ton PM10	4.202	See NOxPM10 worksheet for calculations

Input data for the interpollutant worksheets are from the Annual and Annual based on Monthly worksheets
These worksheets are data and analyses submitted for the PM10 SIP
The AOI worksheet provides area of influence evaluations used to analyze specific episodes in the PM10 SIP
Episode evaluations reveal a variety of source areas for different episodes.
This justifies the use of the entire county, and in some cases more than one county, as the source area for annual interpollutant evalaution.