ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-0:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. 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]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,085 lb; 2nd quarter – 33,085 lb; 3rd quarter – 33,085 lb; and 4th quarter – 33,085 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 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 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]

7. {15} 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]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

10. The CTG shall be fired 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)]

11. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

12. 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 60.4340(b)(1)]

13. 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)]

14. 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)]

15. 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]

16. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 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]

17. 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]

18. 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]

19. 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]

20. 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]

21. 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]

22. 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]

23. 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]

24. 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]

25. 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]

26. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

27. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

29. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

30. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

32. The 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)]

33. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

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

35. 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]

36. 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]

37. 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]

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

39. 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 NOx, CO, and O2 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]

40. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) 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. [District Rule 1081]

41. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

42. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

43. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

44. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

45. 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. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

47. 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]

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 (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. 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)]

50. 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)]

51. 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)]

52. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be

sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

53. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

54. 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 2201 and 4703]

55. 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 and lb/twelve month rolling period). [District Rules 2201 and 4703]

56. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

57. 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]

58. 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]

59. 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]

60. 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]

61. 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]

62. 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]

63. 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]

64. 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]

65. 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]

66. 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-3953-11-0:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. 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]

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

3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 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 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 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]

7. {15} 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]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

9. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

10. The CTG shall be fired 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)]

11. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

12. 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 60.4340(b)(1)]

13. 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)]

14. 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)]

15. 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]

16. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 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]

17. 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]

18. 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]

19. 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]

20. 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]

21. 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]

22. 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]

23. 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]

24. 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]

25. 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]

26. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

27. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

29. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

30. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

32. The 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)]

33. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

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

35. 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]

36. 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]

37. 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]

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

39. 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 NOx, CO, and O2 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]

40. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) 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. [District Rule 1081]

41. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

42. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

43. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

44. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a

valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

45. 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. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

46. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

47. 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]

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 (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. 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)]

50. 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)]

51. 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)]

52. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

53. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

54. 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 2201 and 4703]

55. 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 and lb/twelve month rolling period). [District Rules 2201 and 4703]

56. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-0:
37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. 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]

2. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 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 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 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]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. {1407} 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]

11. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

12. {15} 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]

13. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

14. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

15. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

16. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

17. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

18. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

19. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

20. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

21. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

22. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

23. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

24. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

25. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

26. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

27. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

29. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27\. {1833} 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]

28\. {1834} 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]

29. {1835} 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 NOx, CO, and O2 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 Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} 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]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is 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]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) 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]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-0:
288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

1. 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]

2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

4. {15} 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]

5. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

6. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

7. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

8. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

10. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

11. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

12. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

13. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-0:
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. 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]

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

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} 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]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

8. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

9. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

10. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

11. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

12. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

13. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

14. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

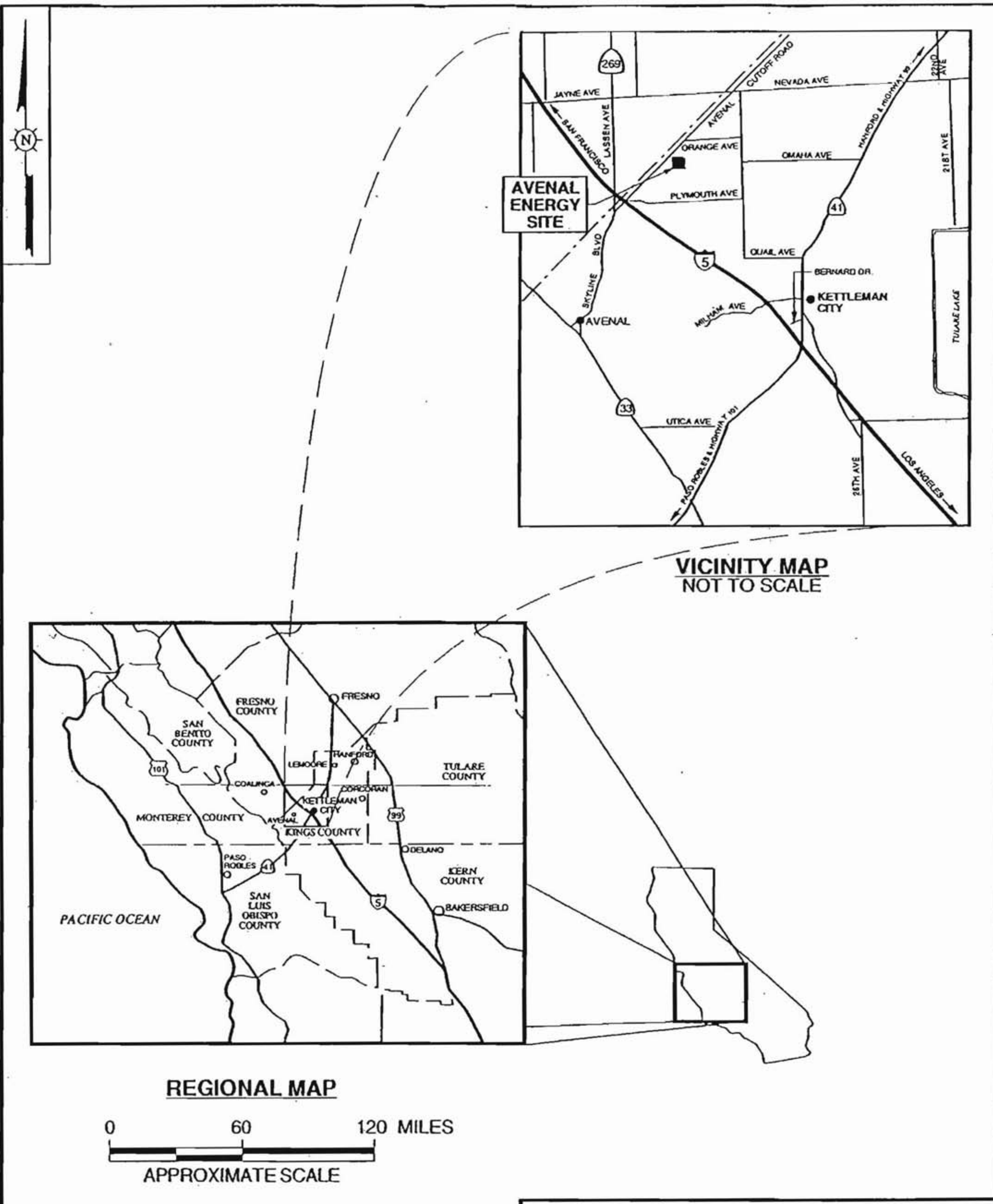
15. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

16. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

ATTACHMENT B

Project Location and Site Plan

290317-AFC-2.0-1 REV1 09/05/06

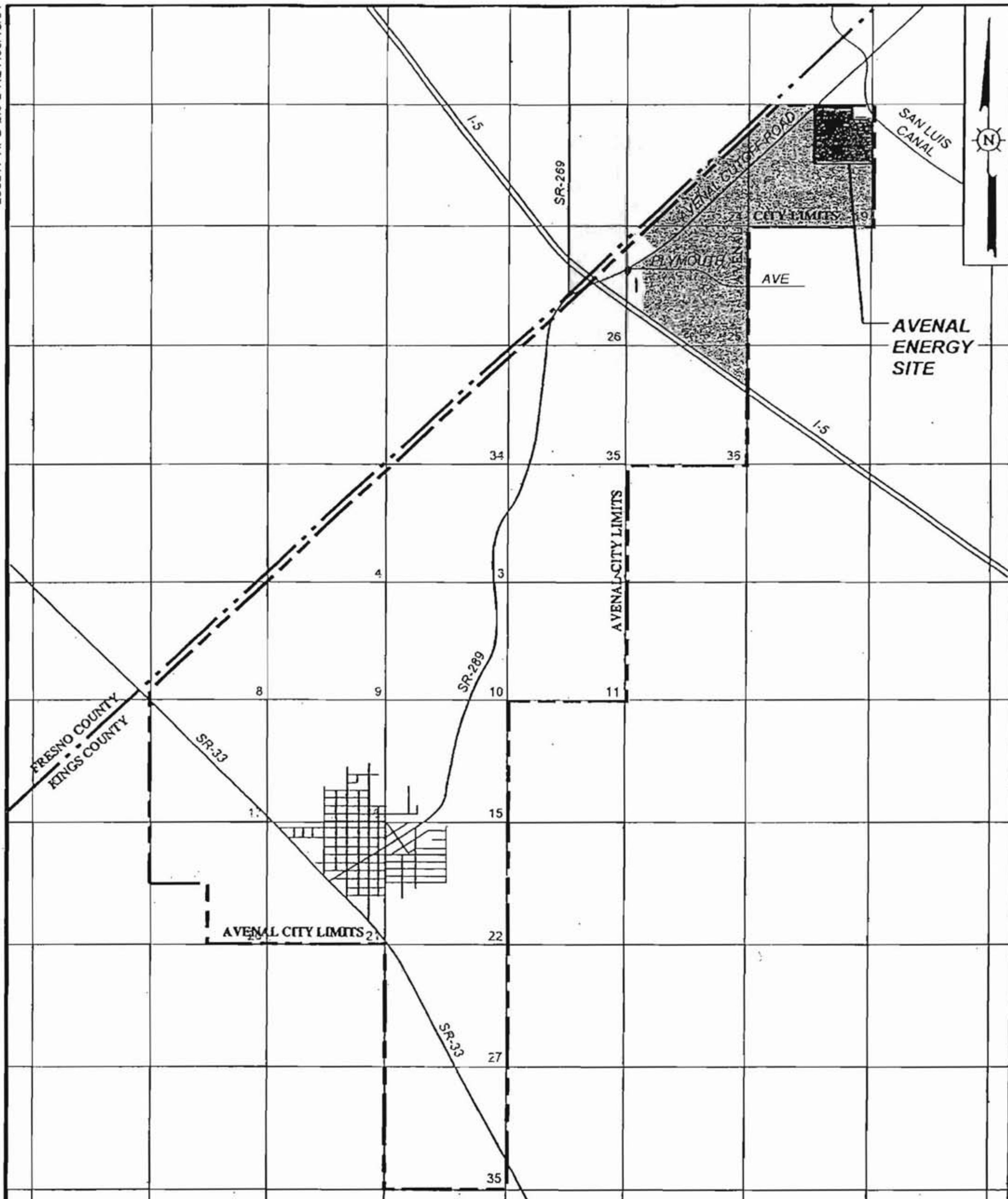


REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY	**FIGURE 2.0-1**

290317-AFC-2.0-2 REV.09/13/01



LEGEND

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

AV

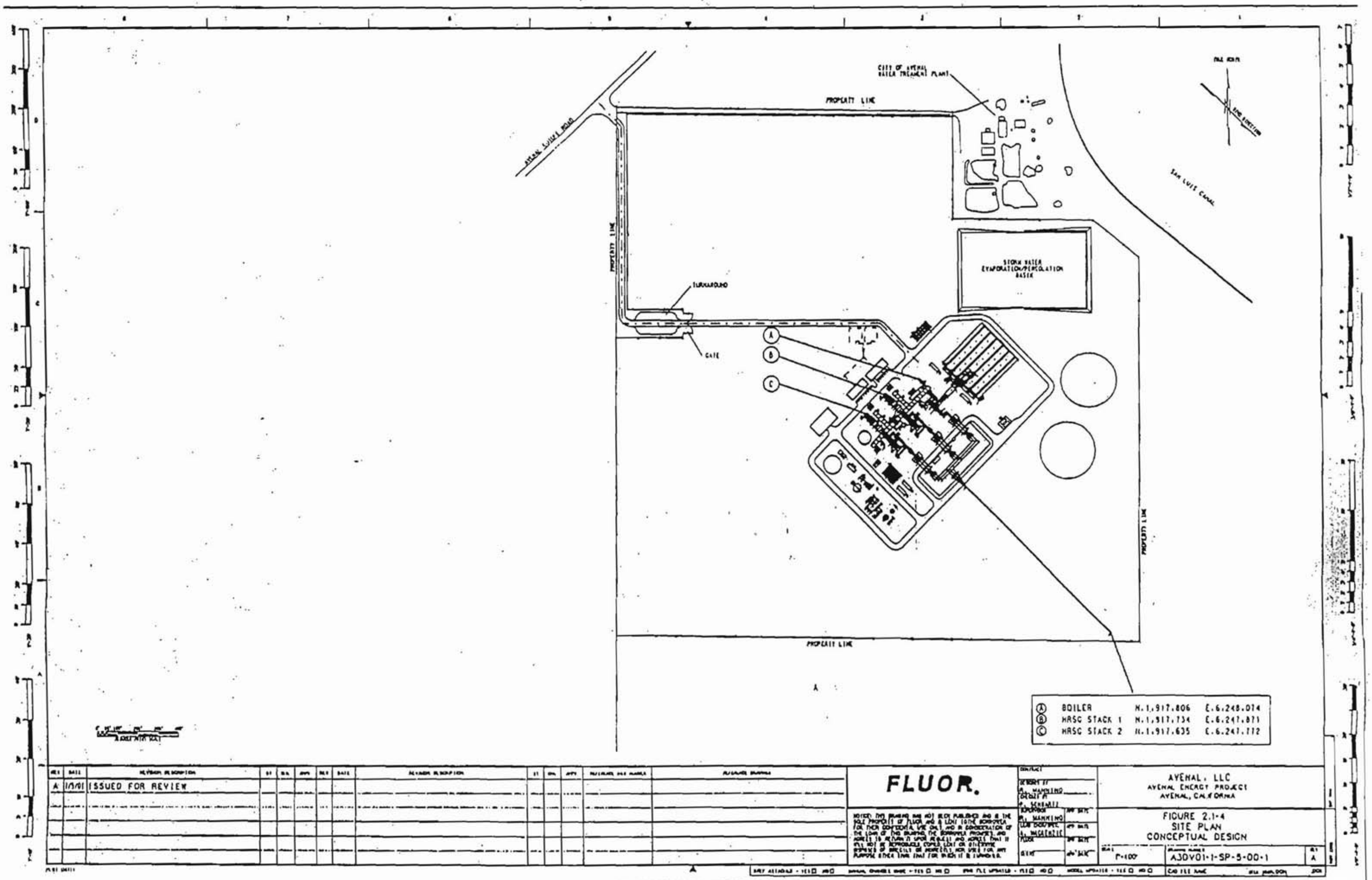
SITE LOCATION

② Rd crosses horiz rd near development

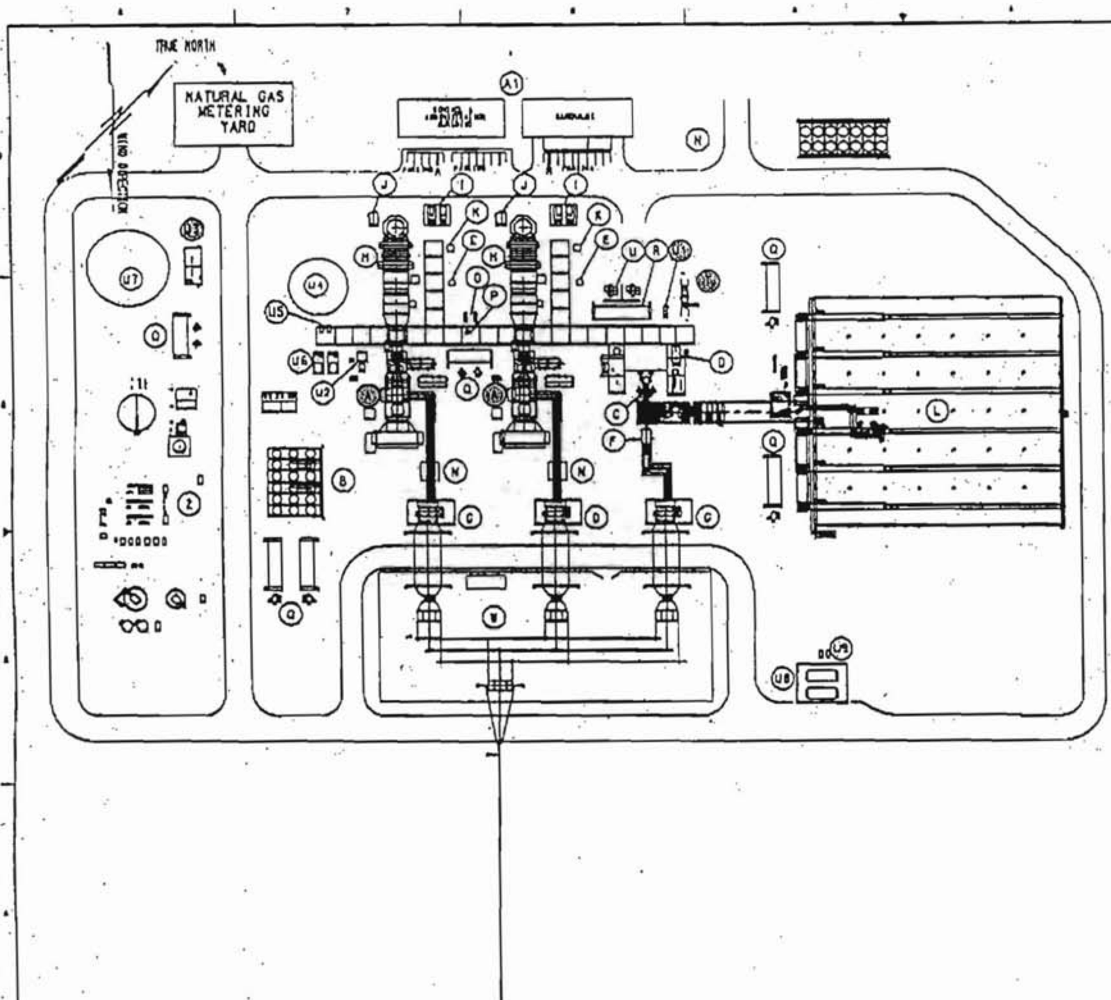
36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY | **FIGURE 2.0-2**



CITY OF AVENAL WATER TREATMENT PLANT
PROPERTY LINE
SAN LUIS CANAL
AVENAL CUTOFF ROAD
STORM WATER EVAPORATION/PERCOLATION BASIN
TURNAROUND
GATE
PROPERTY LINE
PROPERTY LINE
PROPERTY LINE
A BOILER N.1,917,806 E.6,248,014
B HRSC STACK 1 N.1,917,734 E.6,247,871
C HRSC STACK 2 N.1,917,635 E.6,247,772
A 1/3/01 ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1



MAJOR EQUIPMENT LIST

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
G MAIN TRANSFORMERS
H HEAT RECOVERY STEAM GENERATOR
I HP/IP BOILER FEED WATER PUMPS
J CONTINUOUS EMISSIONS MONITORING SYSTEM
K HRSG BLOWDOWN SUMP
L AIR COOLED CONDENSER
M GENERATOR BREAKERS
N CLOSED COOLING WATER AIR COOLER
O CIRCULATING COOLING WATER PUMPS
P CLOSED COOLING WATER EXPANSION TANK
Q POWER DISTRIBUTION CENTER (480 V)
R POWER DISTRIBUTION CENTER (4160 V)
S
T AUXILIARY BOILER
U UNIT AUXILIARY TRANSFORMER
V
W SWITCHYARD
X RAW WATER SOFTENER CLARIFIERS (RWSC)
Y RWSC FILTER PRESS
Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

U1 STANDBY DIESEL GENERATOR
U2 OIL/WATER SEPARATOR
U3 FIREWATER PUMP HOUSE
U4 DEMINERALIZED WATER STORAGE TANK
U5 DEMINERALIZED WATER PUMPS
U6 PLANT/INSTRUMENT AIR COMPRESSORS
U7 RAW WATER/FIREWATER STORAGE TANKS
U8 AMMONIA STORAGE TANKS
U9 AMMONIA TRANSFER PUMPS

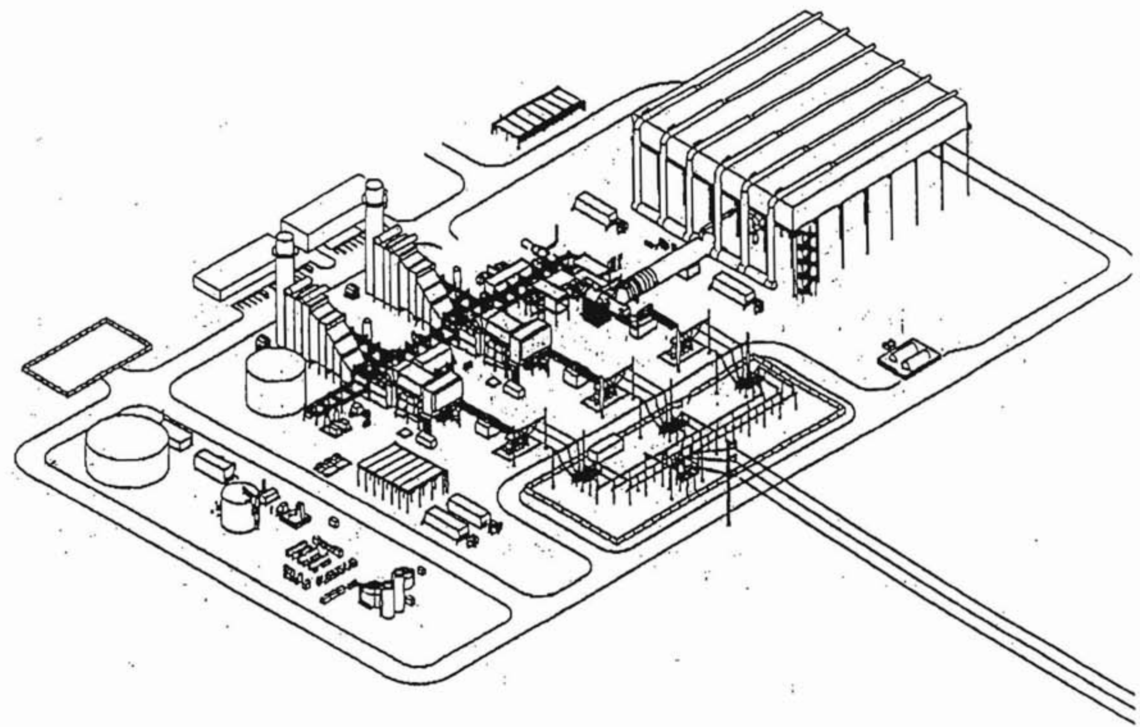
REV	DATE	REVISION DESCRIPTION
A	7/7/01	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

SCALE 1"=125'
A3DY01-1-PP-0-00-1
REV A



REV	DATE	REVISION DESCRIPTION
A	[illegible]	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

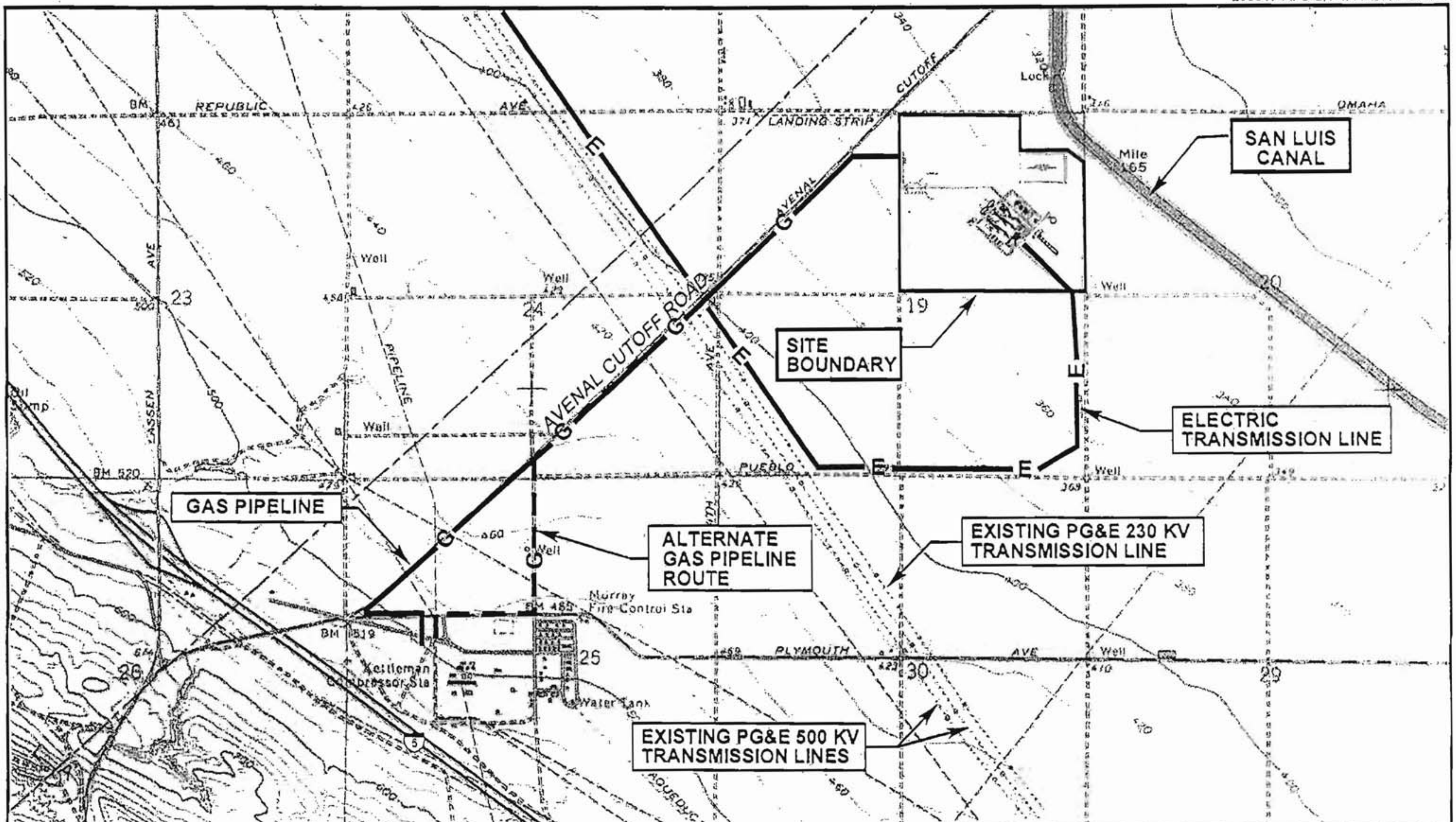
ISO VIEW
CONCEPTUAL DESIGN

SCALE: NONE

A30V01-1-PP-6-00-2

REV A

290317-AFC-2.1-1A REV. 09/05/06



REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY | FIGURE 2.1-1A

ATTACHMENT C

CTG Commissioning Period Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/~~start~~, hour maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential 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.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

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

[25] Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1 101°F Full Load w/ DB[1]	Case 5 63°F Full Load w/ DB[1]	Case 9 32°F Full Load w/ DB[1]	Case 2 101°F Full Load no DB	Case 6 63°F Full Load no DB	Case 10 32°F Full Load no DB	Case 4 101°F 50% Load	Case 8 63°F 50% Load	Case 12 32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.8	359.6	144.1	168.8	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.8	130.8
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	282.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	508.5	525.5	250.3	266.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	98.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.8	2,211.8	1,795.6	1,795.4	1,858.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,496	1,059,836	1,051,531	1,037,822	1,071,653	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.99%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x, lb/hr[2]	17.13	16.34	16.06	13.03	13.03	13.47	7.26	8.01	8.51
NO_x, lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO_2, lb/hr[2,3]	1.66	1.59	1.56	1.27	1.27	1.31	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr[2]	20.66	19.90	19.58	15.86	15.86	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr[2,4]	5.96	5.88	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0025	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.88	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[8]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr [5]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr [6]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr [5]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

1) Includes duct burner firing only up to plant maximum output of 600 MW.
2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.
3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.
4) Based on an assumption that 20% of reported UHC emissions are VOCs.
5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.
6) CH_4 emission factor (kg/MMBtu) = 0.0059
ARB. *Draft Emission Factors for Mandatory Reporting Program,* Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.
7) CO_2 emission factor (kg/MMBtu) = 53.05
ARB. *Draft Emission Factors for Mandatory Reporting Program,* Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.
8) N_2O emission factor (kg/MMBtu) = 0.0001
ARB. *Draft Emission Factors for Mandatory Reporting Program,* Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

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)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

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)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, 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)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

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-3953-10-0, -11-0, -12-0, -13-0, and –14-0)

Units C-3953-10-0 and –11-0 (Turbines)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 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

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective 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 the use of a selective catalytic reduction system with NO_X emissions of 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). 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 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). 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 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-0 and –11-0 (Turbines)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 6.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 4.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 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

The following options are ranked based on their emission factor:

1. 4.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.
2. 6.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

Step 4 - Cost Effective 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 limit CO emissions to 2.0 ppmv @ 15% O_2 (3-hour average, excluding startup and shutdown). This will be achieved with the use of an oxidation catalyst and firing on natural gas fuel. This is higher than 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 limiting the CO emissions to 2.0 ppmv @ 15% O_2 (3-hour average, excluding startup and shutdown) using an oxidation catalyst and firing on natural gas fuel. The facility has proposed to use an oxidation catalyst and fire the units on natural gas, to assure these turbines achieve CO emissions of less than or equal to 2.0 ppmv @ 15% O_2 (3-hour average, excluding startup and shutdown). Therefore, BACT is satisfied.

Units C-3953-10-0 and –11-0 (Turbines)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 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. 1.5 ppmvd VOC @ 15% O_2
2. 2.0 ppmvd VOC @ 15% O_2

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 VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet 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 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.

Units C-3953-10-0 and –11-0 (Turbines)

IV. 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 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 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 natural gas fuel 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.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. 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 filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-0 and –11-0 (Turbines)

V. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 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. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, 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.

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 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 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

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective 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 has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. 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 NO_X emissions of less than 9.0 ppmvd @ 3% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for CO emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 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. Natural gas fuel with LPG backup

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 solely use 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 natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 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. Natural gas fuel with LPG backup

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 solely use 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 natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

IV. 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 1.1:2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 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. Natural gas fuel with LPG backup

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 solely use 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 natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO_X emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 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

The following options are ranked based on their emission factor:

1. Certified NO_X emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective 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 has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. 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 Certified NO_X emissions of 6.9 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any achieved in practice BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Oxidation Catalyst

SJVAPCD BACT Clearinghouse Guideline 3.1.4 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

The following options are ranked based on their control efficiency:

1. Oxidation Catalyst

Step 4 - Cost Effective 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.

However, this engine has been UL Certified, and the UL certification does not include a oxidation catalyst, and the addition of a oxidation catalyst would void the UL certification, which is required for firewater pump engines. Therefore, the oxidation catalyst option will not be required.

Step 5 - Select BACT

BACT for the emission unit is satisfied by the facility's proposed CO emissions of 0.447 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 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

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective 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.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

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

The following options are ranked based on their control efficiency:

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)
2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - Cost Effective 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.

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

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 BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of $\leq$ 1.0 g NO_X/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_X/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_X value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_X/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_X/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_X/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>NO_X (annual):</u>

$$\frac{2.8\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 265\ lb\ NO_X/year$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/year

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_X control efficiency of $\geq$ 90% can be calculated as:

<u>NO_X (annual):</u>

$$\frac{7.4\ \cancel{g}^{(1)}}{\cancel{hp\text{-}hr}} \times \frac{(1-0.9)}{1} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 70\ lb\ NO_X/year$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$$

[1] Pursuant to AP-42 (07/00) the NO_X value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately \$28,000, the capital cost for installing an air to fuel ratio controller would be \$5,300, and the overall installation cost would be \$2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between \$8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of \$1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A\ (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where:
A = Equivalent annual capital cost of the control equipment
P = Present value of the control equipment including installation
i = interest rate (10% used as default value)
n = equipment life (10 years used as default value)

Using a total capital cost of \$35,800 in the above equation results in an equivalent annual cost of \$5,826/year. Adding this equivalent annual cost to the annual operating cost of \$1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to \$6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_X, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt} - Cost_{basic}$), to determine if this control technology is cost effective.

To determine E_{CO}, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173\ lb\ CO/year$$

PE_{CO} = 173 lb CO/year = 0.0865 ton CO/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

<u>CO (annual):</u>

$$\frac{11.6\ \cancel{g}^{(2)}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{(1-0.8)}{1}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\text{-}\cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

PE_{CO} = 220 lb CO/year = 0.11 ton CO/year

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\text{-}\cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 37\ lb\ VOC/year$$

PE_{VOC} = 37 lb VOC/year = 0.0185 ton VOC/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.10\ \cancel{g}^{(3)}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{(1-0.5)}{1}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\text{-}\cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

PE_{VOC} = 5 lb VOC/year = 0.0025 ton VOC/year

[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)
[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

E_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET ($/yr) = (0.0975 x $9,700) + (0.016 x $5,000) = $1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to $6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining 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 NO_X emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 80% CO control efficiency catalyst (rich-burn engine with NSCR or equal)

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

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 80% CO control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective 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 has proposed the engine will be equipped with an oxidation catalyst that will provide 90% control of CO emissions. 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 used of an oxidation catalyst with 90% control of CO emissions. The facility has proposed to install an oxidation catalyst with 90% control of CO emissions. Therefore, BACT is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

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

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective 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 has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. 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 used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. 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:	Derek Fukuda
From:	Matthew Cegielski – Technical Services
Date:	April 28, 2008
Facility Name:	Avenal Power Center
Location:	Avenal Cutoff Road and San Luis Canal, Avenal, CA
Application #(s):	C-3953 10-0, 11-0, 12-0, 13-0, 14-0
Project #:	C-1080386

A. RMR SUMMARY

Categories	10-0 CT #1	11-0 CT #2	12-0 NG Aux Boiler	13-0 DICE Emeg Fire Pump	14-0 NG ICE Emeg Gen	Project Totals	Facility Totals
Prioritization Score	0.6	0.6	0.0	NA[1]	0.1	1.3	1.3
Acute Hazard Index	0.0	0.0	0.0	N/A[2]	0.2	0.2	0.2
Chronic Hazard Index	0.0	0.0	0.0	N/A[2]	0.0	0.0	0.0
Maximum Individual Cancer Risk (10^{-6})	0.02	0.02	0.01	0.01	0.0	0.1	0.1
T-BACT Required?	No	No	No	No	No		
Special Permit Conditions?	No	No	No	Yes	No		

1 Prioritization for this unit was not conducted since it has been determined that all diesel-fired IC engines will result in a prioritization score greater than 1.0.

2 Acute and Chronic Hazard Indices were not calculated since there is not risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Units 10-0, 11-0, 12-0, 14-0

No special conditions required.

Units 13-0

1. The PM10 emissions rate shall not exceed **0.15** g/hp-hr based on US EPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

2. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102] N
3. The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed **50** hours per year. [District Rules 2201, and 4702 and 17 CCR 93115] N

B. RMR REPORT

I. Project Description

Technical Services received a request on April 28, 2008 to perform a Risk Management Review for a proposed installation of a 600 MW Power Plant.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculations were calculated for the units as referenced in the following table.

Unit	Source	Reference
Combustion Turbine 10-0	HEARTS NG Turbine	VCAPCD
Combustion Turbine 11-0	HEARTS NG Turbine	VCAPCD
NG Auxiliary Boiler 12-0	HEARTS NG 10-100 MMBTU/Hr External Combustion	VCAPCD
NG Emergency ICE 14-0	HEARTS NG Internal Combustion <1000 HP	VCAPCD

The AERMOD model was used, with the parameters outlined below and meteorological data for 2004 from Fresno to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Combustion Turbines Unit 10-0, 11-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	44.2	**Closest Receptor (m)**	1202
Stack Diameter. (m)	5.78	**Type of Receptor**	Residential
Stack Exit Velocity (m/s)	19.3	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	367	**Fuel Type**	NG
Burner Rating (MMBtu/hr)	2,356.5		

Analysis Parameters NG Auxiliary Boiler 12-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.3	**Closest Receptor (m)**	1202
Stack Diameter. (m)	0.81	**Type of Receptor**	Residence
Stack Exit Velocity (m/s)	12.2	**Burner size MMBtu/hr**	37.4
Stack Exit Temp. (°K)	476.5		

Analysis Parameters Diesel ICE Emergency Fire Pump 13-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	5.49	**Closest Receptor (m)**	1202
Stack Diameter. (m)	0.15	**Type of Receptor**	Residence
Stack Exit Velocity (m/s)	42.2	**PM_{10} g/hp-hr**	0.15
Stack Exit Temp. (°K)	784.3	**BHP**	288
Max Hours per Year	50		

Analysis Parameters NG Emergency ICE Unit 14-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	3.05	**Closest Receptor (m)**	1202
Stack Diameter. (m)	0.2	**Type of Receptor**	Residence
Stack Exit Velocity (m/s)	71.3	**Throughput (MMBTU/yr)**	355
Stack Exit Temp. (°K)	698	**BHP**	860
Max Hours per Year	50		

AAQA. In addition to the RMR, Technical Services performed an Ambient Air Quality Analysis (AAQA) on the project. Emissions are listed in the table below, for concentrations refer to the AAQA modeling profile.

lbs/hr	Stacks 1 and 2 Unit 10 and 11 Each CTs	Stack 3 Unit 12 Aux Boiler	Stack 4 Unit 13 Diesel Fire Pump	Stack 5 Unit 14 NG Emergency Generator
NOx	16.4	0.41	2.16	1.9
CO	72.8	1.38	0.28	1.14
PM10	9.2	0.19	0.04	0.06
SOx	1.9	0.11	0.0	0.02

lbs/yr	Each CTs	Aux Boiler	Diesel Fire Pump	Emergency Generator
hours/yr	8760	1251	50	50
NOx	143,951	513	108	95
CO	637,788	1727	14	57
PM10	80,656	233	2	3
SOx	16,694	132	0	1

Criteria Pollutant Modeling Results*

	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	Fail[1]	Fail[1]

*Results were taken from the attached PSD spreadsheet.
[1]The predicted ambient air quality impacts for these criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with each unit is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this 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.

Attachments:

A. HARP output files &AERMOD dispersion map
B. Prioritization score with toxic emissions summary, AAQA
C. RMR request from the project engineer

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 12, 2008
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer: Lead Engineer:	Derek Fukuda Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-0, -11-0, -12-0, -13-0, and -14-0		
Project #:	C-1080386		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	June 12, 2008		

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} emissions.

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

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 4.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu
PM_{10}: 0.005 lb/MMBtu

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

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator

One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing

C-3953-10-0: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-0: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-0: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-0: 288 BHP CUMMINS MODEL CFP83-F40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-0: 860 BHP CATERPILLAR MODEL G3512LE NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs 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 SO_X for PM_{10} interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_X for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1080386.

VI. Project Offset Calculations

i. C-3953-10-0 and C-3953-11-0 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	20.97	16.34	16.34	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[1]	11.78	8.91	8.91	23.56
SO_X	N/A[1]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b.. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = $(0.36\ \cancel{\text{gr-S}}/100\ \cancel{\text{dscf}}) \times (1\ \cancel{\text{lb-S}}/7000\ \cancel{\text{gr}}) \times (64\ \text{lb}\ SO_X/32\ \cancel{\text{lb-S}}) \times (1\ \cancel{\text{scf}}/1013\ \cancel{\text{Btu}}) \times (10^6\ \cancel{\text{Btu}}/\text{MMBtu})$
= 0.001 lb-SO_X/MMBtu

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	614,662 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	**637,788 lb/year**
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	142,166 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,7777 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	637,788 lb/year	Scenario 2
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

ii. C-3953-12-0 (Boiler)

The PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.06	1.5	1	3

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] (lb/year)						
Permit Unit	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
C-3953-10-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
C-3953-13-0	108	14	12	2	0	0
C-3953-14-0	95	57	31	3	1	0
Post-project SSPE (SSPE2)	**288,618**	**1,277,374**	**69,222**	**161,550**	**33,521**	**439,944**

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
C-3953-10-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
Post-project SSPE (SSPE2)	**288,415**	**1,277,303**	**69,179**	**161,545**	**33,520**	**439,944**

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

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 1.5:1 (1.000 x 1.5).

VIII. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-0, -11-0, -12-0, -13-0, and -14-0 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

PM10 Interpollutant Offset Ratio Analysis*

County	SOx for PM10	NOx for PM10	Notes
Fresno/Madera	1.866	4.202	Fresno/Madera is a combined evaluation with a shared source area
Kern	1.055	2.157	
Kings	1.000	2.282	Kings/Tulare is a combined evaluation with a shared source area Separate annual evaluations were made for the SIP, but the results establish
Tulare	1.000	2.298	this as one shared area The Kings/Tulare area has a small inventory of local SOx sources and is dominated by pollutant transport from the region; therefore the SOx for PM10 ratio is set to the minimum technical value of 1.000
Merced/Stanislaus	tbd	tbd	prior methodolgy for this area must be reevaluated for technical reasons
San Joaquin	not determined	not determined	insufficient data - a different approach may be required if needed

*** Minimum offset ratio before consideration of distance or other adjustments**

Notes for the Kings-Tulare Interpollutant Analysis

Combined emissions and inventories from Kings and Tulare 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 Kings County in this analysis would also be applicable to Tulare County.

Tons of SOx to Equal Effect of 1 Ton of PM10	1.000	See SOxPM10 worksheet for calculations	Kings County
Tons of SOx to Equal Effect of 1 Ton of PM10	1.000	See SOxPM10 (2) worksheet for calculations	Tulare County

A minimum value of 1.000 is established for technical reasons.
A relationship of less than one-to-one indicates that regional emissions are more dominant than local emissions.

Tons of NOx to Equal Effect of 1 ton PM10	2.282	See NOxPM10 worksheet for calculations	Kings County
Tons of NOx to Equal Effect of 1 ton PM10	2.298	See NOxPM10 (2) worksheet for calculations	Tulare County

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.
Episode trajectories revealed mixing between Kings and Tulare counties during episodes. Annual analysis showed almost identical contributions.
The combined emissions inventories of the two counties are evaluated in comparison to the annual chemical mass balance modeling for each site, and while the observations are slightly different, the resulting interpollutant relationships are almost identical.

PM10 Interpollutant Offset Ratio Analysis

for Kings County

Annual

PM10

	Notes	Units	Estimate	Uncertainty
"Vegetative Burning" Total	1	$\mu g/m^3$	6.55	2.00
Industry Component (30%)	2	$\mu g/m^3$	1.97	
Regional Background (20%)	3	$\mu g/m^3$	0.39	
Industry minus Background		$\mu g/m^3$	1.57	
County Contribution	4	$\mu g/m^3$	0.79	
Organic Carbon PM10 Inventory - Kings and Tulare County	5	ton/day	3.39	
County Impact		$\mu g/m^3$ per ton	0.23	0.30
				0.16

Nitrate

	Notes	Units	Estimate	Uncertainty
Ammonium Nitrate	6	$\mu g/m^3$	15.7	1.4
Regional Background	7	$\mu g/m^3$	1.00	
Ammonium Nitrate minus Background		$\mu g/m^3$	14.66	
County Contribution	8	$\mu g/m^3$	7.33	
NOx Inventory - Kings and Tulare County	9	ton/day	72.20	
County Impact		$\mu g/m^3$ per ton	0.10	0.11
				0.09
Tons of NOx to Equal Effect of 1 ton PM10	10		2.28	2.73
				1.74

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 (Kings - Hanford 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 Kings County is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Kings County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium nitrate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
7. Per SJVUAPCD, regional background of ammonium nitrate is estimated to be 1 $\mu g/m^3$.
8. Contribution from sources within Kings County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. NOx inventory for Kings 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 nitrate County Impact.

PM10 Interpollutant Offset Ratio Analysis
for Kings County

Annual

PM10

	Notes	Units	Estimate	Uncertainty		
"Vegetative Burning" Total	1	μg/m³	6.6	2.0		"Annual based on Monthly" speciation worksheet cells G7 and H7
Industry Component (30%)	2	μg/m³	1.97			"Kings - Hanford" worksheet for speciated rollback analysis
Regional Background (20%)	3	μg/m³	0.39			"
Industry minus Background		μg/m³	1.57			"
County Contribution	4	μg/m³	0.79			"
Organic Carbon PM10 Inventory - Kings and Tulare County	5	ton/day	3.39			" Required to use base year emissions that are related to the observed speciation
County Impact		μg/m³ per ton	0.23	0.30		
				0.16		
Sulfate						
Ammonium Sulfate	6	μg/m³	3.0	0.3		Annual based on Monthly, speciation worksheet cells M7 and N7
Regional Background	7	μg/m³	1.00			"Kings - Hanford" worksheet for speciated rollback analysis
Ammonium Sulfate minus Background		μg/m³	1.99			"
County Contribution	8	μg/m³	0.99			"
NOx Inventory - Kings and Tulare County	9	ton/day	3.15			" Required to use base year emissions that are related to the observed speciation
County Impact		μg/m³ per ton	0.32	0.35		
				0.28		
Tons of SOx to Equal Effect of 1 Ton of PM10	10		0.73	0.87	0.14	Minimum valid technical value = 1.000
				0.57	-0.17	Minimum valid technical value = 1.000

The Kings/Tulare area has a small inventory of local SOx sources and is dominated by pollutant transport from the region; therefore the SOx for PM10 ratio is set to the minimum technical value of 1.000

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 (Kings - Hanford 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 Kings County is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Kings 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 SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 μg/m³.
8. Contribution from sources within Kings County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. NOx inventory for Kings 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.

	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		4.82	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 = 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
5	LINE 2	7.78	4.0	0.0		0.0	0.4		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	45.22	19.2	4.0		0.5	1.6		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	26.55	13.4	2.0		0.4	0.8		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	10.61	2.9	1.2		0.1	0.48		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	5.80	1.9	0.6		0.1	0.24		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	2.26	1.0	0.2		0.0	0.08		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		0.294086989	4.5008		4.5846				60.9543
21		R= SJV	230.9463	14.9088		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	[illegible]												
134	PM10 2010 EI without new controls	L1= Area 5	11.71676419	0.31680007		0.078620969	0.348794276		1.892896835				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				87.0645
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= Area 5	9.60613547	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								49.38328821			
144		Sr= Tulare, Kings								52.7948			
145	•	R= SJV								401.8368			
146	NOx 2010 EI with new controls	L1= Area 5								12.44632963			
147		L2= Areas 5,6,7,8								44.57374448			
148		Sr= Tulare, Kings								47.8723089			
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	[illegible]												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	14.8	0.9	0.6	0.5	0.5	0.5	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	0.2	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	0.4		1.4	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	51.65	25.2	1.8	1.1	0.7	1.3	1.0	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	0.5	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	0.3	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	0.2	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	0.6	0.1		0.0
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.4		1.4	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	46.60	21.4	1.7	1.1	0.7	1.3	1.0	4.2	11.9	3.2	0.0	0.0
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

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
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

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
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

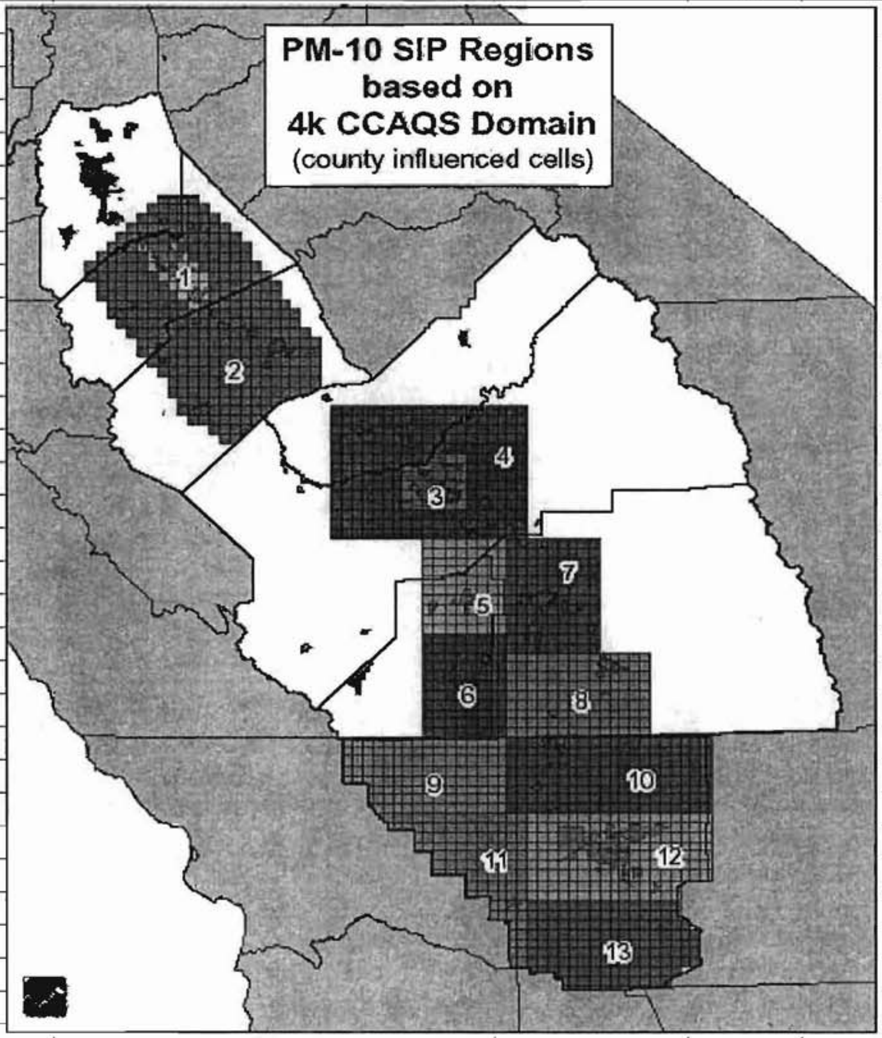
NOTES: Burning profile was switched from wood burning to agricultural burning based on ARB monthly emissions inventory estimates.
Asterisk * denotes AgBWheat profile used; ** denotes WBAlmond (some AgBWheat/WBAlmond used in April/May)

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

Annual	County	Value	Local	PM2.5	Sub regional	Regional
			Areas used			
	Kern	57	12	Kern	Kern	SJV



Derek Fukuda

From: Jim Rexroad [Jim.Rexroad@macquarie.com]

Sent: Monday, June 09, 2008 3:51 PM

To: Derek Fukuda

Cc: Eric Walther; Tracey Gilliland

Subject: Certificates used for Avenal PDOC

Derek,

We are still finishing up the formal table submissions so you can see the actual breakdowns, but here is the list of certificates that we will be using for the project. Note that S-2813-1 will shortly have a transaction coming that will reduce the volume to 50 Tons and the S2321-2 certificate (I have a contract and the ownership change documents will come next week. We should be able to send you the formal table tomorrow or by Thursday. Call me if you have questions.

ERC Certificate No.

VOC
C-897-1
C-898-1
N-724-1
N-725-1
S-2813-1 (derived from)

NOx
C-899-2
N-722-2
N-720-2
N-726-2
N-728-2
C-902-2
S-2814-2
S-2321-2 (derived from)

SOx (conversion to PM10 at 1.4:1)
S-2791-5
S-2790-5
S-2789-5
S-2788-5
N-762-5

PM10
C-896-4
N-721-4
N-723-4

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ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%		
Type of fuel (use table above)	4	GAS
O2 correction (i.e., 3%)	15	%
Enter LB/MMBTU emission factor		
NOx	0.847	LB/MMBTU
CO	0.130	LB/MMBTU
VOC (as methane)	0.000	LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS		
NOx	229.94	ppmv
CO	57.98	ppmv
VOC (as methane)	0.00	ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume --> Grams/Brake Horsepower - Hour

ppmv --> g/Bhp-hr

Variables:

Engine Size:	860	hp
NO_x:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:

Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NOx)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

ppmv	F-factor	$MW_{pollutant}$	20.9	1	1	Conversion #3	1	
1	1	1	(20.9 - O_2%)	Conversion #1	Conversion #2	1	Engine Eff.	=

for NO_x:

230 ~~parts~~	8578 ~~dscf~~	46 ~~lb~~	20.9	~~1 lb-mol~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO:

0 ~~parts~~	8578 ~~dscf~~	28 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

0 ~~parts~~	8578 ~~dscf~~	16 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%		
Type of fuel (use table above)	4	GAS
O2 correction (i.e., 3%)	15	%
Enter LB/MMBTU emission factor		
NOx	2.270	LB/MMBTU
CO	0.130	LB/MMBTU
VOC (as methane)	0.000	LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS		
NOx	616.25	ppmv
CO	57.98	ppmv
VOC (as methane)	0.00	ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume --> Grams Brake Horsepower - Hour

ppmv --> g Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NOx)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

ppmv	F-factor	$MW_{pollutant}$	20.9	1	1	Conversion #3	1	=
1	1	1	(20.9 - O_2%)	Conversion #1	Conversion #2	1	Engine Eff.	

for NO_x:

616 ~~parts~~	8578 ~~dscf~~	46 ~~lb~~	20.9	~~1 lb-mol~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

0 ~~parts~~	8578 ~~dscf~~	28 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

0 ~~parts~~	8578 ~~dscf~~	16 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	=
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

RECEIVED
JUL 0 3 2008
Permits Srvc
S.IVAPCD

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

CEC Comments and Districts Responses

Public Comments / District Response

The comments from the California Energy Commission (Keith Golden) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

CEC Comments – Letter Dated August 12, 2008

CEC Comment #1:

Energy Commission staff is concerned that the integrity of the proposed mitigation may be adversely affected by the annual equivalency demonstration required by SJVAPCD Rule 2201, Section 7. This rule requires the District to demonstrate that emission reduction credits (ERCs) used by the project as offsets are surplus at the time of use.

Please describe whether District compliance with Rule 2201, Section 7 would require any of the offsets to be subject to discounting. Please also confirm whether the offsets identified for the project (on PDOC p. 47) are representative of real and surplus reductions, taking into account possible discounting under Rule 2201, Section 7. Additionally, please identify the original emission reduction site and date, and the method of reduction, for the ERCs that would be used to offset this project.

Districts Response:

Provided the FDOC is issued prior to a finding of failure of the equivalency system, the "at time of use" requirements don't apply. In addition, the District has not failed the equivalency demonstration, and does not expect to fail the demonstration this year. Finally, "at time of use" means at the time of the issuance of the permit (which the District considers to be the FDOC, in this case). Therefore, if a permit is issued without requiring "surplus at time of use credits", as the District subsequently fails to demonstrate equivalency with federal offsetting requirements, there is no affect on the permit. The "surplus at time of use" requirements would only kick in on permits issued after that date.

CEC Comment #2:

Staff would like to verify that using offsets would not disrupt regional progress in attaining PM10 or PM2.5 standards. The SJVAPCD, in Attachment H of the PDOC incorrectly states that the applicant proposed a one-to-one ratio. Please provide the District analysis in "Appendix A" with the Attachment H of the PDOC that supports compliance with Rule 2201, Section 4.13.3.

Districts Response:

The Districts PM_{10} and $PM_{2.5}$ plans both account for the growth in permitted sources in the air district. This growth is compared to the amount of offsets available in the Districts ERC bank to assure that the increase in emissions will not invalidate the Districts PM_{10} and $PM_{2.5}$ plans. Since the growth in permitted sources in the air district and the air districts available offsets have been taken into account when determining both the PM_{10} and $PM_{2.5}$ attainment plans, the use of offsets in this project will not result in the disruption of the attainment plans.

The interpollutant offset ratio for SO_X reductions for PM_{10} increases will remain the same as stated in the PDOC. The Districts analysis of the interpollutant offset ratio has can be seen in Appendix A, which has been included in Attachment H of the PDOC.

CEC Comment #3:

Energy Commission staff concurs with the District that the NOx emission limits for the combustion turbines and duct burners should apply on one-hour rolling averages during all operating conditions, except startup and shutdown periods (as described in PDOC p. 64 and PDOC Condition 26). However, the one-hour NOx emission limit is not consistently described in the PDOC. Please confirm that the value calculated by the District is 17.20 lb/hr (PDOC Condition 26), not 17.44 lb/hr (as shown on p. 64).

Districts Response:

The hourly NO_X emission limit is 17.20 lb/hr. The condition on page 64 of the PDOC has been corrected to be consistent with condition 26 of the PDOC.

CEC Comment #4:

Energy Commission staff recommends limiting ammonia slip to the extent feasible. Although ammonia slip is intrinsic to operation of the selective catalytic reduction system, staff suggests that the District set a performance standard for ammonia slip. Guidance from CARB (Guidance for Power Plant Siting and Best Available Control Technology, September 1999) indicates that an ammonia slip limit of 5 parts per million by volume dry basis (ppmvd) should be achievable. Please consider revising the ammonia slip limits for the combustion turbines.

Districts Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on NO_X reductions.

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

CEC Comment #5:

The New Source Performance Standard (NSPS) Subpart KKKK applies to stationary combustion turbines and emissions from any associated duct burners, and it replaces earlier requirements in NSPS Subpart Db and Subpart GG. The PDOC (p. 55) shows requirements from NSPS Subpart Db, although the project appears to be exempt. Similarly, the PDOC (p. 63) states that the turbines meet the applicability requirements of Subpart GG when the project appears to be exempt. Please clarify whether the project is indeed exempt from NSPS Subparts Db and GG.

Districts Response:

The stationary combustion turbines and duct burners in this project are subject to Subpart KKKK and are therefore exempt from Subparts Db and GG. An additional compliance section was added to state that the duct burners are exempt from Subpart Db. The compliance section for Subpart GG already states that the turbines are exempt from its requirements.

ATTACHMENT K

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Shirley Rivera) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Email Dated August 15, 2008

EPA Comment #1:

For the purposes of EPA's review of the PDOC evaluation and PDOC, although not required as part of our PSD permit application review/permit development process, we are in the process of identifying whether information provided by the Applicant through the PSD permit application process is consistent with the information in the District's evaluation. (Note: The Applicant provided sections from its CEC AFC that includes the Air Quality and Public Health sections, which presumably is information that the District evaluation also is based. PSD review has been triggered for NOx, CO, and PM.)

We would like to ensure that, at a minimum, those data sets and assumptions shared between the PSD and PDOC processes that contribute to the determination of the potential-to-emit, BACT, and assumptions for the air quality analysis/modeling are consistent. At this time, we simply would like to make the District aware that this evaluation is in process. To the extent that we identify inconsistencies during our review, we will address them as part of our PSD permit process.

Districts Response:

Thank you for the notification.

EPA Comment #2:

The emission limits proposed for each combustion turbine generator (CTG), Units C-3953-10-0 and C-3953-11-0, are 4.0 ppmvd @ 15% O2. EPA is aware of CTGs achieving CO emissions less than 4.0 ppmvd @ 15% O2. Therefore, please provide confirmation whether the District's evaluation considered achieved in practice CO ppm levels less than 4.0 ppmvd @ 15% O2. If so, please provide reasons why a lower level was eliminated from consideration.

Districts Response:

The facility has proposed to lower their CO emission limit to 2.0 ppmvd @ 15% O_2.

ATTACHMENT L

CURE Comments and District Responses

Public Comments / District Response

The comments from California Unions for Reliable Energy (Loulena Miles, attorney at Adam Broadwell Joseph & Cardozo) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Public Comments – Email Dated August 18, 2008

<u>Public Comment #1:</u>

THE SJVAPCD MUST SET LIMITS FOR GREENHOUSE GAS EMISSIONS

The law is now settled that greenhouse gases are pollutants subject to regulation under the Clean Air Act (CAA). Therefore, Air District permits must include a Best Available Control Technology (BACT) analysis and a permit limit for greenhouse gas emissions. The PDOC contains neither. Accordingly, the PDOC is deficient and must be revised to require BACT for greenhouse gas emissions.

<u>Districts Response:</u>

According to the Advanced Notice of Proposed Rulemaking for Regulating Greenhouse Gas Emissions under the Clean Air Act, Federal Register Vol. 73, No. 147, pg. 44420 (July 30, 2008),

"The Supreme Court's conclusion that GHGs are "air pollutants" under the CAA did not automatically make these pollutants subject to the PSD program. A substance may be an "air pollutant" under the Act without being regulated under the Act. The Supreme Court directed the EPA Administrator to determine whether GHG emissions from motor vehicles meet the endangerment test of CAA section 202(a). A positive finding of endangerment would require the Administrator to then set standards applicable to GHG emissions from motor vehicles under the Act. The positive finding itself would not constitute a regulation requiring actual control of emissions. GHGs would become regulated pollutants under the Act if and when EPA subjects GHGs to control requirements under a CAA provision other than sections 112 and 211(o)."

EPA has not added control requirements for GHG's in the CAA, therefore GHG's are not regulated air pollutants and are not subject to the PSD program. In addition, the District has not been delegated the PSD program by EPA. Therefore, even if GHGs do become regulated pollutants, the District will continue to have no jurisdiction to regulate them until the EPA decides to delegate the PSD program to the District.

Based on the information discussed in the paragraphs above, an evaluation of GHG's is not necessary to determine if this project is approvable.

Public Comment #2:

The PDOC limits CO emissions from the combustion turbine generators (CTGs) to 4.0 ppm at 15% O_2 regardless of whether the duct burners are firing based on the use of an oxidation catalyst.[1] The PDOC's determination that 4.0 ppm CO emissions are BACT is incorrect and fails to recognize that a number of power plants in the same category and class of source have achieved lower CO emission rates than proposed by the Applicant.

Districts Response:

The facility has proposed to lower their CO emission limit to 2.0 ppmvd @ 15% O_2.

Public Comment #3:

THE PM_{10} BACT DETERMINATION FOR CTGs IS DEFICIENT

The PDOC limits PM_{10} emissions from the combustion turbine generators (CTGs) to 9.0 lbs/hr without duct firing and 11.8 lbs/hr with duct firing, using natural gas fuel. The PDOC determined that BACT for PM_{10} emissions from this Project's two General Electric (GE) 7FA CTGs would be the use of natural gas fuel with an LPG backup. This determination is incorrect and fails to recognize that a number of power plants in the same category and class of source that have achieved lower PM_{10} emission rates than proposed by the Applicant.

Districts Response:

The District Top-Down BACT Analysis did not consider any PM_{10} emissions control other than the use of an air inlet filter, lube oil vent coalescer and natural gas fuel.

District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM_{10} as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

---

[1] SJVAPCD PDOC Attachment F-5.

Furthermore, District BACT Policy, Section IV, states that BACT Determinations are to be based upon the control technologies and methods for the same or similar source categories, listed in the District's BACT Clearinghouse for the calendar quarter during which the application is deemed complete. This application was deemed complete in the 1st quarter of 2008, therefore it is subject to the BACT Guideline for the source categories contained in the BACT Clearinghouse at that time. Based on the completion date of this application, the BACT requirements for the units in this project would not change even if the BACT Guidelines were changed in subsequent quarters.

The permitted PM_{10} emissions limit for each CTG in this project is 11.78 lb/hr. This emission limit is lower other GE Frame 7A, combined cycle, turbines with duct burners at power plants which have recently been approved by the CEC. The Victorville 2 Hybrid Power Plant (approved 7/16/08) was permitted with a PM_{10} emission limit of 18.0 lb-PM_{10}/hr. The Colusa Generating Station (approved 4/23/08) was permitted with a PM_{10} emission limit of 20.1 lb-PM_{10}/hr. The Los Medanos Energy Center referenced in your comment has a permitted PM_{10} emission limit of 16.2 lb-PM_{10}/hr. In addition, the PM_{10} emission limits for the two turbines at the Cosumnes Power Plant are not comparable since they are not equipped with duct burners.

Public Comment #4:

SJVAPCD's LIMITS ON AMMONIA SLIP ARE NOT BACT

The PDOC and attached permit conditions propose an unreasonably high ammonia slip limit of 10 ppm @ 15% O_2.[2] This ammonia slip rate was selected by the Applicant in the Application for Certification (AFC).[3] The PDOC incorporates this rate without any BACT analysis. The PDOC dismisses the need to do a BACT analysis on the basis that "the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NOX. The emissions from a control device that is determined by the District to be BACT are not subject to BACT."

Districts Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with

[2] SJVACPD Avenal PDOC p. 7 and PDOC Attachment A.
[3] Avenal Energy AFC, p. 6.2-41.

Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on NO_X reductions.

You commented that initial ammonia slip rates below 5 ppmv have been observed on some combustion turbines using SCR. Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.5 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.