JUN 06 2016

Donald Januszek
DTE Stockton, LLC
2626 Washington Street
Stockton, CA 95203

RE: Final - Authority to Construct / Certificate of Conformity (Significant Modification)
Facility Number: N-645
Project Number: N-1142618

Dear Mr. Januszek:

The Air Pollution Control Officer has issued the Authority to Construct permit to DTE Stockton, LLC for a biomass-fired boiler, at 2526 W Washngton Street in Stockton, CA. Enclosed are the Authority to Construct permit and a copy of the notice of final action to be published approximately three days from the date of this letter.

Notice of the District's preliminary decision to issue the Authority to Construct permit was published on August 29, 2015. The District's analysis of the proposal was also sent to CARB and US EPA Region IX on August 26, 2015. All comments received following the District's preliminary decision on this project were considered.

Comments received by the District during the public notice period resulted in revisions to the HCl monitoring requirements. These changes were minor and did not trigger additional public notification requirements, nor did they have any impact upon the Best Available Control Technology determination or on the amount of offsets required for project approval.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Prior to operating with the modifications authorized by the Authority to Construct, you must submit an application to modify the Title V permit as an administrative amendment in accordance with District Rule 2520, Section 11.5. Application forms have been enclosed for your use. These forms may also be found on the District's website at www.valleyair.org.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Nick Peirce at (209) 557-6400.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:JH

Enclosures

cc: Tung Le, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-36-3 **ISSUANCE DATE:** 05/25/2016

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: ATTN: PAYABLE DEPARTMENT
2526 W WASHINGTON ST
STOCKTON, CA 95203

LOCATION: 2526 W WASHINGTON ST
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, DRY SORBENT INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

CONDITIONS

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Authorities to Construct N-645-36-0, N-645-36-1, and N-645-36-2 shall be cancelled upon the implementation of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits in the following quantities: 1st quarter - 6,930 lb, 2nd quarter - 6,930 lb, 3rd quarter - 6,930 lb, and 4th quarter - 6,930 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

N-645-36-3 : May 25 2016 11:11AM -- HARADERJ : Joint Inspection NOT Required

5. Prior to operating equipment under this Authority to Construct, the permittee shall surrender VOC emission reduction credits in the following quantities: 1st quarter - 2,175 lb, 2nd quarter - 2,175 lb, 3rd quarter - 2,175 lb, and 4th quarter - 2,175 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201] Federally Enforceable Through Title V Permit

6. ERC Certificate Number N-1007-5 (or one or more certificates split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. The permittee is authorized to utilize SOx ERC to satisfy the PM10 offset obligation specified in this permit. The use of SOx ERC to satisfy the PM10 offset obligation shall be conducted at an interpollutant offset ratio of 1:1. [District Rule 2201] Federally Enforceable Through Title V Permit

7. ERC Certificate Numbers S-3715-1 and S-4485-1 (or one or more certificates split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

8. 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 and 40 CFR 60.43b(f) and (g)] Federally Enforceable Through Title V Permit

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

10. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

11. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

12. 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] Federally Enforceable Through Title V Permit

13. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102] Federally Enforceable Through Title V Permit

14. The permittee shall conduct a performance tune-up of the boiler in accordance with the requirements of 40 CFR 63 Subpart JJJJJJ at least every 24 months. The permittee shall submit a signed statement in the Notification of Compliance Status indicating that each tune up was conducted. [40 CFR 63.11210] Federally Enforceable Through Title V Permit

15. The permittee shall calibrate and maintain in operation a selective catalytic reduction (SCR) system designed to reduce NOx emissions from the boiler exhaust stack to less than or equal to 0.040 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

16. The electrostatic precipitator shall be provided with continuous monitoring equipment showing the secondary power input, as specified in 40 CFR 63, Subpart JJJJJJ. The monitoring equipment shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201 and 40 CFR 63.11224] Federally Enforceable Through Title V Permit

17. The electrostatic precipitator shall be in operation whenever the boiler is operated on biomass. The electrostatic precipitator secondary power input, on a 12-hour block average, shall be maintained at or above the lowest 1-hour average secondary power input measured during the most recent performance test demonstrating compliance with the PM emission limitation, in accordance with Table 3 of 40 CFR 63, Subpart JJJJJJ. Transient voltage fluctuations due to arcs and sparks, or similar automatic functions of the electrostatic precipitator, shall not constitute deviations. The electrostatic precipitator shall be maintained in accordance with the manufacturer's recommendations, a copy of which shall be maintained on site. [District Rule 2201, 40 CFR 63.11221 and 40 CFR 64] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

18. The wet scrubber shall be provided with monitoring equipment that continuously monitors and records the effluent pH and flow rate of the scrubber liquid. [District Rule 2201] Federally Enforceable Through Title V Permit

19. The wet scrubber shall be in operation whenever the boiler is operated on biomass. The effluent pH and liquid flow rate, calculated on a rolling 30-day average basis, shall be maintained at or above the average pH and flow rate established during the most recent HCl source test. [District Rules 2201 and 4002] Federally Enforceable Through Title V Permit

20. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Startup is defined as the period of time beginning when the unit is heated to the operating temperature and pressure from a shutdown status or hot standby condition and ending only when the unit is firing on biomass or wood residue and is in compliance with the NOx, SOx, and CO emission limits for non-startup operation and with the minimum ESP secondary power input specified in this permit. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

22. Shutdown is defined as the period of time during which a unit is taken from operational to nonoperational status by allowing it to cool down from its operating temperature and pressure to an ambient temperature, or to a hot standby condition. Duration of shutdown shall not exceed 12 hours. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

23. Hot standby condition is defined as a condition in which all fuel feed has been curtailed and the boiler is secured at a temperature greater than the current ambient temperature. [District Rule 4352] Federally Enforceable Through Title V Permit

24. Flame stabilization is defined as any period in which supplemental use of a liquid or gaseous fuel is required in instances including control of one or more pollutants, or to alleviate or prevent unanticipated equipment outages or emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

25. This unit shall only be fired on biomass and wood residue, except that the unit may also be fired on natural gas during startup, shutdown, and flame stabilization periods. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

26. The total annual heat input to the unit from natural gas combustion shall not exceed 612,324 MMBtu in any one calendar year. [District Rules 4001 and 40 CFR 60.44b(d)] Federally Enforceable Through Title V Permit

27. Biomass is defined as any organic material originating from plants, not chemically treated and not derived from fossil fuels, including but not limited to products, by-products, and residues from agriculture, forestry, aquatic and related industries, such as agricultural, energy or feed crops and residues, orchard and vineyard prunings and removal, stone fruit pits, nut shells, cotton gin trash, corn stalks and stover, straw, seedhulls, sugarcane leavings and bagasse, aquatic plants and algae, cull logs, eucalyptus logs, poplars, willows, switchgrass, alfalfa, bark, lawn, yard and garden clippings, paper (unprinted), leaves, silvicultural residue, tree and brush pruning, sawdust, timber slash, mill scrap, wood and wood chips, and wood residue. Biomass does not include tires, material containing sewage sludge, or industrial, hazardous, radioactive, or municipal solid waste. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

28. Wood residue consists of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

29. Biomass and wood waste fuels shall not include pressure-treated wood and shall not contain compounds listed in Title 22, California Code of Regulations, 66261.24(a)(2)(A) in excess of the following concentrations by weight: 500 ppm antimony and/or antimony compounds, 500 ppm arsenic and/or arsenic compounds, 1,000 ppm asbestos, 10,000 ppm barium and/or barium compounds (excluding barite), 75 ppm beryllium and/or beryllium compounds, 100 ppm cadmium and/or cadmium compounds, 500 ppm chromium (VI) compounds, 2,500 ppm chromium and/or chromium (III) compounds, 8,000 ppm cobalt and/or cobalt compounds, 2,500 ppm copper and/or copper compounds, 18,000 ppm fluoride salts, 1,000 ppm lead and/or lead compounds, 20 ppm mercury and/or mercury compounds, 3,500 ppm molybdenum and/or molybdenum compounds, 2,000 ppm nickel and/or nickel compounds, 100 ppm selenium and/or selenium compounds, 500 ppm silver and/or silver compounds, 700 ppm thallium and/or thallium compounds, 2,400 ppm vanadium and/or vanadium compounds, and 5,000 ppm zinc and/or zinc compounds. [District Rule 4102]

30. The permittee shall be allowed a 24-month period to evaluate the operational variability and optimum control effectiveness of the proposed exhaust emission control system to meet the design emission rate of 0.040 lb-NOx/MMBtu. During the evaluation period, the permittee shall operate and maintain the boiler and the emission control system in such a manner as to minimize NOx emissions, and shall perform all required source testing and monitoring. The evaluation period shall begin upon the first day of the initial source test, and shall terminate after 24 months. [District Rule 2201] Federally Enforceable Through Title V Permit

31. During the 24-month evaluation period, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

32. During the 24-month evaluation period, the permittee shall submit annual status reports on the performance of the NOx emission control system. Each status report is due at the same time as the annual source test report. The status report shall, at a minimum, include actual operating time, calculated heat input to the boiler, actual NOx emissions as measured by the CEM system, daily and annual average actual NOx emission rates (in lb/MMBtu), and an analysis of system performance to date and expected performance for the next year. [District Rule 2201] Federally Enforceable Through Title V Permit

33. If NOx emissions continue to exceed, or are projected to exceed, 0.040 lbs/MMBtu on a block 24-hour average basis after the 24-month evaluation period, the permittee shall submit a final report containing all monitoring and source test data to the District within 90 days after the end of the evaluation period. The report shall include a detailed analysis of all factors that prevent achievement of the expected emission rate, as well as a detailed explanation of the steps taken to operate and maintain the boiler and the emission control system in such a manner as to minimize emissions. The report shall also propose an enforceable NOx emission limit, which shall not exceed 0.065 lb/MMBtu on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

34. Upon submittal of the report, the District shall re-evaluate BACT requirements for NOx from this class and category of source and establish an appropriate BACT emissions limit. Within 30 days of receipt of the District's determination, the permittee shall submit an Authority to Construct application to incorporate the revised emissions limit. In no case shall the NOx emission limitation be higher than 0.065 lbs/MMBtu on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

35. Following the 24-month evaluation period and prior to issuance of an Authority to Construct with a revised NOx emission limit, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

36. If NOx emissions do not exceed, and are not projected to exceed, the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis after the 24-month evaluation period, then the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis shall become an enforceable NOx emission limit. If the permittee fails to submit the required final report within 90 days after the end of the evaluation period, the permittee shall be considered to stipulate that an enforceable NOx emission limit of 0.040 lb/MMBtu on a block 24-hour average basis is achievable and will be made enforceable. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

37. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.065 lb-NOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis as defined in District Rule 4352 (amended December 15, 2011). [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

38. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.74 lb-NOx/MMBtu. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

39. NOx emissions from this biomass-fired boiler shall not exceed 140.00 pounds in any one hour, as specified in District Rule 4301, Section 6.0. [District Rule 4301] Federally Enforceable Through Title V Permit

40. Except during periods of startup and shutdown, The emission rate from this biomass-fired boiler shall not exceed 0.09 lb-CO/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

41. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.67 lb-CO/MMBtu. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

42. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.054 lb-SOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

43. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.27 lb-SOx/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

44. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.0214 lb-PM10/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201] Federally Enforceable Through Title V Permit

45. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.078 lb-PM10/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

46. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.030 lb-PM/MMBtu [40 CFR 60.43b(h)(1) and 40 CFR 63.11201] Federally Enforceable Through Title V Permit

47. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.009 lb-VOC/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201] Federally Enforceable Through Title V Permit

48. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.068 lb-VOC/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

49. The ammonia slip emission rate from this biomass-fired boiler shall not exceed 40 ppmvd @ 3% O2. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 4102]

50. HCl emissions from this biomass-fired boiler shall not exceed 19,980 pounds in any rolling 365 consecutive day period. HCl emissions shall be calculated daily for comparison to this annual limit using the daily boiler heat input determined pursuant to 40 CFR Part 75, Appendix F, Equation F-15 and the emission factor calculated in the most recent HCl source test. If HCl emissions from the biomass boiler, including emissions from startup, shutdown or malfunction periods are determined to have exceeded 19,999 pounds in any rolling 365-day period, the owner/operator shall submit an Authority to Construct application to comply with 40 CFR 63 Subpart DDDDDD requirements within 30 days of the exceedance. [District Rules 2201 and 4002] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

51. Emissions from this biomass-fired boiler shall not exceed any of the following limits: 1st Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 2nd Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 3rd Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 4th Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC. Compliance with NOx, SOx, and CO limits shall be determined from CEM data. Compliance with PM10 and VOC limits shall be calculated using emission factors (the most recent source test results for non-startup/shutdown operation, or the startup/shutdown emission factors at all other times), heat input to the boiler, and operating time. [District Rule 2201] Federally Enforceable Through Title V Permit

52. 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 shall be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

53. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

54. 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 1081 and 2201] Federally Enforceable Through Title V Permit

55. This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits within 60 days of achieving the maximum steam production rate, but no more than 180 days after initial startup, and at least once every 12 months thereafter. The PM source test required by condition 55 may be conducted in lieu of PM10 testing required by this condition, provided all PM is assumed to be PM10 as specified in condition 64. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

56. This unit shall be tested for compliance with the PM emission limit within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 36 months thereafter. [40 CFR 60.8(a), 40 CFR 60.43b(d), and 40 CFR 63.11220(a)] Federally Enforceable Through Title V Permit

57. This unit shall be tested to determine the HCl emission factor within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. The permittee shall measure and record the effluent pH and liquid flow rate in the wet scrubber every 15 minutes during the source test. [District Rule 2201] Federally Enforceable Through Title V Permit

58. Permittee shall test fuel to determine the higher heating value at least once every 12 months. [District Rules 1081 and 2201, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

59. Permittee shall test fuel for contaminants within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter, or whenever requested by the District. The District shall be notified at least 15 days prior to scheduled sample collection. [District Rules 2201 and 4102, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

60. Testing of the fuel for contaminants shall be conducted on a representative sample collected upstream of and as close as practicable to the fuel metering bins. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

61. Fuel shall be tested for contaminants in accordance with the wet extraction test procedure detailed in Title 22 California Code of Regulations, Division 4.5, Chapter 11, Appendix II. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

62. NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or ARB Method 100 and EPA Method 19. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

63. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

64. PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

65. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081] Federally Enforceable Through Title V Permit

66. PM emissions required to be source tested under condition 55 shall be determined using EPA Methods 5 or 17 (filterable (front half) PM only), and 19. [40 CFR 60.43b(d)(2) and 40 CFR 63.11212] Federally Enforceable Through Title V Permit

67. Stack gas oxygen shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

68. SOx emissions for source test purposes shall be determined using EPA Method 6 or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

69. VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

70. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

71. HCl emissions for source test purposes shall be determined using EPA Methods 26 or 26A, and 19. [District Rule 2201] Federally Enforceable Through Title V Permit

72. Testing for fuel higher heating value shall be conducted using ASTM Method D5865-01a or District-approved equivalent method. [District Rules 1081 and 4352, and 40 CFR 75 Appendix F] Federally Enforceable Through Title V Permit

73. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, SOx, and CO2. Additionally, the exhaust stack shall be equipped with a flow monitor. The CEM shall meet the requirements of 40 CFR parts 60 (for CO) and 75 (for NOx, SOx, and CO2), except as specified in 40 CFR 60, Subpart Db, and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. The CEM shall be used to demonstrate compliance with the Rule 2201 emission limits. [District Rules 1080 and 2201] Federally Enforceable Through Title V Permit

74. Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) in accordance with 40 CFR 60.48b, and 40 CFR 60 Appendices B and F. The sampling and analyzing cycle shall be completed every successive 10 second period, and the recording cycle shall be completed every successive 6 minute period. The COMS shall be used to demonstrate compliance with the opacity requirements of 40 CFR 43b(f) and (g). [District Rules 1080 and 2201, and 40 CFR 60.48b(a)] Federally Enforceable Through Title V Permit

75. Permittee 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] Federally Enforceable Through Title V Permit

76. 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] Federally Enforceable Through Title V Permit

77. 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 either an O2 or CO2 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] Federally Enforceable Through Title V Permit

78. 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] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

79. Permittee shall perform a relative accuracy test audit (RATA), as specified by 40 CFR Part 75, Appendix B, 2.3.1 for the NOx, SOx, and O2 or CO2 CEM,, at least once every two successive QA operating quarters (as defined in 40 CFR 72.2) unless the monitor satisfies the requirements for reduced RATA frequencies in Section 2.3.1.2. Permittee shall perform a RATA, as specified by 40 CFR Part 60, Appendix F for the CO CEM, at least once every four calendar quarters. Permittee shall perform a cylinder gas audit (CGA) or relative accuracy audit (RAA), as specified by 40 CFR Part 60, Appendix F for the CO CEM in three of four calendar quarters, but no more than three quarters in succession. The District must be notified at least 30 days prior to any RATA, and a test plan shall be submitted for approval at least 15 days prior to testing. The results of each RATA shall be submitted to the District within 60 days thereafter. [District Rule 1080] Federally Enforceable Through Title V Permit

80. 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 75, Appendix B for the NOx, SOx, and O2 or CO2 CEM, and in 40 CFR Part 60, Appendix F for the CO CEM. [District Rule 1080] Federally Enforceable Through Title V Permit

81. 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] Federally Enforceable Through Title V Permit

82. When using measurements taken by the CO2 analyzer for emission compliance determinations, the following formula shall be used to convert the emission concentration referenced at 12 percent CO2 to an emission concentration referenced at 3 percent O2: E at 3%O2 = E at 12%CO2 x (CO2 F-Factor ÷ O2 F-Factor) x (100 ÷ 12) x (20.9 - 3) ÷ 20.9. Where, the CO2 F-Factor is in terms of scf CO2/MMBtu and the O2 F-Factor is in terms of dscf/MMBtu at 0% O2. Permittee may choose to use the default CO2 and O2 F-Factors for wood listed in 40 CFR Method 19, or may choose to use site-specific F-Factors. If using site specific F-Factors, permittee shall re-determine the site-specific F-Factors annually using at least 9 fuel samples. The site-specific F-Factors shall be determined in accordance with EPA Method 19. [District Rules 1080 and 2080, and 40 CFR 60] Federally Enforceable Through Title V Permit

83. Permittee shall keep records of site-specific F-Factor determinations, including the date of each determination, the corresponding CO2 F-Factor, and the corresponding O2 F-Factor. [District Rules 1080 and 2080, and 40 CFR 60] Federally Enforceable Through Title V Permit

84. Permittee shall maintain records of the date and duration of start-up and shutdown periods. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

85. Permittee shall record the heat input to the unit from each fuel combusted on a daily basis. Permittee shall maintain records of the annual capacity factor for each fuel combusted on a 12-month rolling average basis, and shall update the annual capacity factor for each fuel at the end of each calendar month. [District Rules 1070 and 4001, and 40 CFR 60.49b(d)(1)] Federally Enforceable Through Title V Permit

86. Permittee shall retain and maintain on site all data from the continuous opacity monitoring system. [District Rules 1070 and 4001, and 40 CFR 60.39b(f)] Federally Enforceable Through Title V Permit

87. Permittee shall maintain, on at least a monthly basis, an operating log that includes the type and quantity of fuel used, and the higher heating value of each fuel, as determined by Section 6.3 of District Rule 4352 (12/15/11), or as certified by a third party fuel supplier. [District Rules 1070 and 4352] Federally Enforceable Through Title V Permit

88. Permittee shall maintain records of emissions from this boiler on a calendar quarter basis. Records of quarterly emissions shall be updated at least once each calendar month in which the boiler operates. [District Rule 2201] Federally Enforceable Through Title V Permit

89. Permittee shall maintain records of HCl emissions from this boiler on a rolling consecutive day basis. Records of HCl emissions shall be updated at least once each calendar day in which the boiler operates. [District Rules 2201, 4002, and 4102] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

90. The permittee shall maintain records of the criteria used to establish that the unit qualifies as a small power production facility under section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)) and that the waste material the unit is proposed to burn is homogeneous (not including refuse-derived fuel). [40 CFR 60.2175(w)] Federally Enforceable Through Title V Permit

91. Permittee shall keep the results of the most recent source test, including the measure HCl emission rate and the applicable scrubber operating parameters, onsite. [District Rule 2201] Federally Enforceable Through Title V Permit

92. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Biomass-Fired Power Plant – As Built Revisions

Facility Name:	DTE Stockton, LLC	Date:	Revised May 20, 2016
Mailing Address:	2526 W. Washington St. Stockton, CA 95203	Engineer: Lead Engineer:	James Harader Nick Peirce
Contact Person:	Michael Blakey		
Telephone:	(209) 320-3731		
Project #:	N-1142618		
Deemed Complete:	March 30, 2015		

I. Proposal

In addition to the original proposal, shown below, this application review has been revised as follows:

- As a result of comments from the Center for Biological Diversity, the applicant proposed to modify the proposed HCl monitoring conditions better clarify the applicant's proposed method for keeping track of rolling 12-month emissions. A full response to the comments from the Center for Biological Diversity is included in Appendix L.

- Following public notification, the District determined that the biomass power plant qualifies as a replacement unit for Federal NSR. The Federal Major Modification discussion in this evaluation has been revised to account for the unit qualifying as a replacement unit. The revisions to the Federal Major Modification discussion did not result in any changes to the proposed permit conditions.

Original Proposal

DTE Stockton, LLC ("DTE") was issued Authority to Construct (ATC) permits in June 2011 to convert their existing coal-fired power plant into a biomass-fired power plant. The previous project, N-1101175, also included the modification of several existing units to convert the units from coal handling units to biomass and/or dry sorbent handling units. Finally, the previous project included the removal of several emission units, including the coal-fired combustors, to be replaced by a new biomass-fired boiler. DTE has implemented the changes to the biomass and dry sorbent receiving and handling systems; however, DTE is proposing as-built changes to the Authority to Construct for the biomass-fired boiler.

The following revisions to the biomass boiler are proposed:

1. DTE is proposing to use emission reduction credit (ERC) certificates that weren't listed in their original ATC for the biomass-fired boiler (ATC N-645-36-0). The ATC condition requires the project to be re-noticed if alternative ERC certificates are proposed.

2. DTE was unable to procure the full quantity of emission reduction credits necessary to offset PM10, as required in ATC N-645-36-0. As such, they are proposing to reduce the annual PM10 emission limit for the biomass-fired boiler to 107,296 lb per rolling 12-months.

3. DTE is proposing that the permitted definitions of the terms "startup" and "shutdown" be revised such that the definitions are consistent with the definitions listed in District Rule 4352.

4. DTE is requesting to revise the monitoring requirements for their HCL scrubber.

The previously issued ATC for the biomass-fired boiler (See Appendix B) will be cancelled and an as-built ATC will be issued for the biomass-fired boiler.

DTE received their Title V Permit on April 13, 2001. This modification can be classified as a Title V significant modification pursuant to Rule 2520, Section 3.20, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the ATC.

II. Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)[1]
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)
Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4203	Particulate Matter Emissions from Incineration of Combustible Refuse (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4304	Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters (10/19/95)
Rule 4305	Boilers, Steam Generators, and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators, and Process Heaters – Phase 3 (10/16/08)
Rule 4320	Advanced Emission Reduction Operations for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4351	Boilers, Steam Generators, and Process Heaters – Phase 1 (8/21/03)
Rule 4352	Solid Fuel Fired Boilers, Steam Generators, and Process Heaters (5/18/06)
Rule 4801	Sulfur Compounds (12/17/92)
40 CFR 64	Compliance Assurance Monitoring

[1] This project was deemed complete prior to the latest amendments to District Rule 2201; therefore, the April 21, 2011 version of District Rule 2201 is applicable to this project.

CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notification
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

This facility is located at 2526 W. Washington St. in Stockton, California, within the Port of Stockton. The District has determined that this facility is not within 1,000 feet of the outer boundary of the nearest K-12 school. Therefore, the school notification requirements of California Health & Safety Code 42301.6 do not apply to this application.

IV. Process Description

DTE previously operated a 49.9 MW (net) coal-fired electrical generating station that uses two 280 MMBtu/hr CFB combustors. The existing coal receiving operations have been converted to handle biomass, the coal storage silos and day tanks have been removed, the limestone receiving and day tanks have been converted to handle trona/dry-sorbent for acid gas control, and the existing combustors have been removed to make way for a single stoker-type boiler. The existing emergency engines and cooling tower will not be modified. ATC's have already been issued and implemented for the biomass handling and trona/limestone operations. This permitting action solely addresses the as-built revisions to the biomass-fired boiler.

The biomass-fired boiler is a stoker-type unit, meaning that fuel is burned on a grate as opposed to being burned in suspension or in a fluidized bed. The boiler is equipped with a vibrating grate, upon which fuel from the charging hopper is spread using a number of distribution devices. The vibrating grate consists of a series of grate elements in a horizontal arrangement. Half of the horizontal grate elements are fixed and half oscillate to move fuel along the grate toward the ash discharge. Combustion air is fed into the combustion chamber through ports located under each grate section, while overfire air enters the combustion chamber through additional ports spaced around the combustion chamber and arranged to ensure optimal mixing and complete combustion. Bottom ash, essentially all unburned fuel residue that is too massive to become entrained in the flue gas as fly ash, is removed from the stoker grate at the opposite end from the fuel charging hopper. Pursuant to the source category description presented in Section 2.2 of *Emission Factor Documentation for AP-42 Section 1.1: Bituminous and Subbituminous Coal Combustion* (where much of the information on solid fuel-fired boilers is available), this unit is classified as a spreader stoker.

For startup operations, the boiler is equipped with a 100 MMBtu/hr natural gas-fired startup burner. This will be used to gradually heat the boiler when starting up, in order to ensure the unit is not physically damaged by heat stresses, and to bring the combustion chamber up to sufficiently high temperature to allow the biomass fuel to ignite. Once the biomass fuel is ignited, the boiler will be gradually transitioned to firing exclusively on biomass fuel. The startup burner will also be utilized to complete combustion of any remaining solid fuel residue when shutting the unit down.

Emissions from the boiler will be controlled by a variety of mechanisms, which are detailed in Section VI of this document. Fly ash and bottom ash from the boiler will be routed to separate fly ash and bottom ash silos, currently permitted as N-645-12-4. Fly ash will be periodically loaded out from the silo into trucks for sale as a commodity. Load out will be accomplished through a telescoping spout using water spray to reduce PM_{10} emissions.

SO_x and acid gas emissions from the boiler will be controlled using dry sorbent injection. Typically, Trona is used as the dry-sorbent; although other sorbents may be used. Trona is a mined mineral form of sodium carbonate and is received at the site as a coarse powder delivered by trucks, which are unloaded to the limestone receiving silos, converted to trona use, by screw conveyor. Trona from the silos will be routed by enclosed conveyor to the existing limestone day tanks, also converted to trona use, and then to an enclosed pulverizer where the coarse powder is ground to a fine dust to maximize the surface area. Trona is then injected pneumatically into the flue gas immediately downstream of the combustion chamber, where it reacts with SO_x and other acidic gases such as hydrogen chloride (HCl). The resulting sulfate particulate is readily removed in the multiclone and electrostatic precipitator (ESP).

While HCl is controlled by dry-sorbent injection, this control may not be sufficient to ensure that DTE is not a major source of hazardous air pollutants. In order to ensure that DTE remains below the major source threshold for HCl, DTE proposes to supplement dry-sorbent injection with a wet scrubber to remove additional HCl from the exhaust stream. Water is sprayed into the scrubber tower in fine droplets which absorb the highly water-soluble HCl. To preserve the pollution control efficiency, a caustic such as sodium hydroxide is used to maintain the pH balance of the scrubbing solution as it is recirculated through the scrubber.

Finally, the boiler will be served by the existing steam turbine generator and a 43,000 gal/min cooling tower. Water is routed through the combustion chamber in water tubes to make saturated steam, then routed through the combustion chamber again in the superheater section, and then passed repeatedly (with some reheating) through a turbine connected to an electrical generator to make electricity. Spent steam is then condensed in a heat exchanger/condenser and returned to the boiler. Water on the other side of the heat exchanger/condenser is routed to the cooling tower in a secondary loop.

V. Equipment Listing

Pre-Project Equipment Description:

The biomass-fired boiler is a new unit.

Post-Project Equipment Description:

N-645-36-3: 54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, TRONA INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

VI. Emission Control Technology Evaluation

The combustion of biomass fuel in the boiler will result in emissions of NO_x, SO_x, PM_{10}, CO, VOC, and HCL, while ammonia injection will result in ammonia "slip" emissions.

SO_x emissions from fuel combustion are the result of fuel-bound sulfur being oxidized in the combustion process. DTE proposes to control SO_x emissions using a dry-sorbent injection system. The sorbent adsorbs the gaseous SO_2 or SO_3, reacting with it to produce a sulfate that can be removed from the flue gas with the rest of the PM_{10}. Dry-sorbent also has a similar affect on other acid gases, particularly HCl. However, because HCl is a hazardous air pollutant, DTE also proposes to use a wet scrubber for additional HCl control to ensure that the boiler is not a major source of hazardous air pollutants.

PM_{10} emissions from the boiler will be controlled using a combination of a multiclone and an ESP. In a multiclone, the flue gas is routed through several drastic course changes which cause suspended particulate matter to collide with the multiclone walls and fall out of suspension. In an ESP, the flue gas passes through the corona induced by an array of charged wires. Passing through the corona induces a charge on the particulate matter within the flue gas, which causes the particle to be drawn in the direction of an oppositely-charged collector plate, which it impacts and adheres to. When enough the material collected begins to interfere with the collection efficiency, the plates are rapped to cause the collected dust to fall off into a collection hopper.

CO and VOC emissions from the boiler are primarily the result of incomplete combustion. However, highly efficient combustion that minimizes CO and VOC emissions also tends to maximize NO_x emissions. DTE has proposed to control CO and VOC emissions using proper combustion supplemented by an oxidation catalyst. This catalyst uses excess oxygen in the flue gas to oxidize CO and VOC to CO_2 and gaseous H_2O.

Any operation that combusts fuel has the potential to result in NO_x emissions, which can come from the oxidation of fuel-bound nitrogen ("fuel NOx") or from the oxidation of nitrogen in the combustion air at high temperature ("thermal NO_x"). Fuel NO_x is largely, although not directly, proportional to the fuel nitrogen content, and therefore essentially fixed in the design phase. Thermal NO_x is a function of several variables, including peak combustion temperature, the residence time at peak temperature, nitrogen concentration, and oxygen concentration or flame stoichiometry. Combustion modifications can be useful in adjusting these variables by reducing the peak temperature, nitrogen concentration, and stoichiometry. For example, by injecting some combustion air below the grate and the rest of the combustion air through the overfire air ports above the grate, the combustion zone can be expanded and the peak temperature reduced.

DTE has proposed to control NOx emissions using a selective catalytic reduction (SCR) system. A selective catalytic reduction system reduces NOx by reacting the NOx with ammonia in the presence of a catalyst. SCR is a well-known technology for controlling NOx emissions from gaseous or liquid fuel-fired boilers, but the use of SCR on solid-fuel fired units is much more recent.

DTE's proposal to achieve an extremely low emission rate using SCR provides an opportunity to determine the lowest achievable emission rate that is appropriate for this control. Since the

District is in "extreme" non-attainment of the 8-hour ozone National Ambient Air Quality Standard (NAAQS), and since the 2007 Ozone Attainment Plan puts a premium on NO_x emission reductions, the District has recently allowed sources proposing novel NO_x control techniques an evaluation period in which to establish the lowest achievable emission rate applicable to their NO_x controls.

Therefore, the District has determined that DTE will be allowed a 24-month evaluation period in which to demonstrate that compliance with the target NO_x emission limit can be achieved, or that the target NO_x emission limit is not achievable. The control system vendor has observed that the uncontrolled emissions from DTE's Woodland facility are approximately 0.33 lb/MMBtu, and the proposed SCR system would reduce that to 0.033 lb/MMBtu on average. Since the target emission rate will presumably become the basis of an enforceable emission limit at the end of the evaluation period, the vendor has further proposed a margin for compliance of approximately 20%, resulting in an average emission rate of 0.040 lb/MMBtu. This average will not be enforceable during the evaluation period, but has been used in calculating the quarterly mass emission limits that are enforceable. In addition, a firm NO_x emission limit of 0.065 lb/MMBtu will be established; any emissions in excess of the firm limit will be subject to enforcement action. At the end of the evaluation period, the District will review the operational and emissions data to determine whether reasonably consistent compliance with the target limit has been demonstrated. DTE will then be required to submit an ATC application to modify the permit and establish the firm emission limit associated with the SCR.

Commissioning Period:

This plant has already been commissioned; therefore, commissioning requirements do not apply to this project.

VII. General Calculations

A. Assumptions

- Maximum heat input rate when fired on biomass is 699 MMBtu/hr
- Annual average heat input rate is 641 MMBtu/hr
- The maximum heat input rate when only fired on natural gas is 100 MMBtu/hr
- F-factor for biomass combustion is 9,240 dscf/MMBtu (0% O_2)
- F-factor for biomass combustion is 1,830 dscf/MMBtu (100% CO_2)
- Startups and shutdowns may require 12 hours per day and 24 hours per year
- Annual operating time is 8,424 hours per year including startups and shutdowns
- Biomass fuel combustion is 1,951 tons per day and 470,080 tons per year
- Facility-wide NO_x emissions are limited to 215,657 lb/yr
- PM10 emissions from the biomass combustor will not exceed 107,296 lb/year
- Other assumptions will be stated as they are made

B. Emission Factors

The following table shows the proposed control devices, startup & shutdown emission limit, expected emission factor (if applicable), and firm emission limit for each pollutant:

Boiler Emission Control Device Summary				
Pollutant	Control Device(s)	Limits (lb/MMBtu)		
		Startup	Expected	Firm
NO_x	Proper combustion, SCR	0.74	0.04	0.065
PM_{10}	Multiclone & ESP	0.078	N/A	0.0214
SO_x	Dry-sorbent injection	0.27	0.025	0.054
CO	Oxidation catalyst	0.67	N/A	0.09
VOC	Oxidation catalyst	0.068	N/A	0.009

In addition, the applicant has proposed an ammonia slip limit of 40 ppmvd @ 3% O_2. This concentration can be converted to a lb/MMBtu format as follows:

EF = $(40/10^6)$ x (1 lb-mol/379.5 ft^3) x (17 lb/lb-mol) x (9,240 ft^3/MMBtu) x
(20.95 ÷ (20.95 – 3.00))
EF = 0.019 lb/MMBtu

C. Emission Calculations

1. Pre-Project Potential to Emit (PE1)

This is a new unit; therefore, PE1 is equal to zero.

2. Post-Project Potential to Emit (PE2)

DTE expects to operate the facility up to 24 hours per day and 8,400 hours of normal operation per year. Daily emissions are based on 12 hours of startup or shutdown and 12 hours of normal operation per day. All startup/shutdown operation is at 699 MMBtu/hr to reflect the worst-case potential emissions from combustion of the fuel with highest heating value, while normal annual operation is at 641 MMBtu/hr, which assumes average fuel heat content and represents the projected actual emissions from this facility. In addition, the applicant has proposed several long-term emission limits for specific pollutants, which will be enforceable, in a practical manner, using continuous emissions monitoring system (CEMS) data.

For NO_x:

As shown in the portion of this document devoted to discussion of Rule 4301 (Fuel Burning Equipment), the boiler is subject to a flat limit of 140 lb/hr for NO_x emissions. For comparison, the proposed startup emission limit and heat input rating can be used to calculate hourly emissions during startup as follows:

PE2 = (0.74 lb-NO_x/MMBtu) x (699 MMBtu/hr) = 517.26 lb-NO_x/hr

Since this exceeds the 140 lb-NO_x/hr limit from Rule 4301, the rule limit will be used to calculate the contribution during startup and shutdown operation. It is noted that compliance with this rule limit is expected to be feasible, since startup operation will initially revolve around the 100 MMBtu/hr natural gas-fired startup burner, and long before the boiler reaches its maximum rated heat input the SCR catalyst would have reached sufficiently high temperature to become effective in reducing NO_x emissions.

PE2 = (0.065 lb/MMBtu) x (12 hr/day) x (699 MMBtu/hr) + (140 lb/hr) x (12 hr/day)
PE2 = 2,225.2 lb/day

The applicant has proposed to limit NO_x emissions to 215,350 pounds per year, enforceable using CEMS data.

PE2 = 215,350 lb/yr

For SO_x:

Daily SO_x emissions are calculated using the short-term emission limit of 0.054 lb/MMBtu, which represents the worst-case fuel sulfur content, for steady-state operation and the startup emission limit of 0.27 lb/MMBtu for startup operation.

PE2 = [(0.054 lb/MMBtu) x (12 hr/day) + (0.27 lb/MMBtu) x (12 hr/day)] x (699 MMBtu/hr)
PE2 = 2,717.7 lb/day

For annual emissions, the long-term expected emission limit of 0.025 lb/MMBtu is used for steady-state operation. This represents the expected fuel sulfur content on a 30-day rolling average basis.

PE2 = [(0.025 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.27 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 139,140 lb/yr

For PM_{10}:

PE2 = [(0.0214 lb/MMBtu) x (12 hr/day) + (0.078 lb/MMBtu) x (12 hr/day)] x (699 MMBtu/hr)
PE2 = 833.8 lb/day

The applicant has proposed to limit the annual PM10 emissions to 107,296 pounds, enforceable using the biomass and natural gas throughput and the source test data.

PE2 = 107,296 lb/yr

For CO:

PE2 = [(0.09 lb/MMBtu) x (12 hr/day) + (0.67 lb/MMBtu) x (12 hr/day)] x (699 MMBtu/hr)
PE2 = 6,374.9 lb/day

PE2 = [(0.09 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.67 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 495,836 lb/yr

For VOC:

PE2 = [(0.009 lb/MMBtu) x (12 hr/day) + (0.068 lb/MMBtu) x (12 hr/day)] x (699 MMBtu/hr)
PE2 = 645.9 lb/day

PE2 = [(0.009 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.068 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 49,600 lb/yr

For NH_3:

Ammonia emissions are associated with certain short-term health risks, so ammonia slip from the SCR system must be calculated and taken into consideration as part of the health risk assessment.

PE2 = (0.019 lb/MMBtu) x (24 hr/day) x (699 MMBtu/hr) = 318.7 lb/day

PE2 = [(0.019 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.019 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 102,622 lb/yr

Alternatively, this boiler will perate using a natural gas-fired startup burner rated at 100 MMBtu/hr during startup and shutdown operations. A comparison of emission factors easily demonstrates that potential emissions from the startup burner are less than potential emissions when firing biomass during startup. Therefore, emissions from the startup burner are subsumed into the overall startup emissions and do not require separate calculation. For convenience, the emission factors are compared in Table 7 below:

Startup Emission Factors (lb/MMBtu)					
Fuel	**NO_x**	**SO_x**	**PM_{10}**	**CO**	**VOC**
Biomass	0.74	0.27	0.078	0.67	0.068
Natural gas	0.1	0.00285	0.0076	0.084	0.0055
Biomass > Natural gas?	Yes	Yes	Yes	Yes	Yes

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

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

The following pre-project stationary source potential to emit, prior to the conversion of the plant from a coal-fired plant to a biomass fired power plant, was obtained from District Project N-1101175.

SSPE1 (lb/yr)				
NO_x	**SO_x**	**PM_{10}**	**CO**	**VOC**
215,657	228,490	170,357	693,502	44,120

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

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

The following post-project potential to emit reflects all of the ATC's that have been implemented in order to convert the facility from a coal-fired power plant to a biomass-fired power plant, along with the as-built boiler emissions.

SSPE2 (lb/yr)						
Unit	**Description**	**NO_x**	**SO_x**	**PM_{10}**	**CO**	**VOC**
ATC N-645-8-7	Dry Sorbent silo	0	0	11	0	0
ATC N-645-9-7	Dry Sorbent silo	0	0	11	0	0
ATC N-645-10-5	Dry Sorbent day tank	0	0	0	0	0
ATC N-645-11-5	Dry Sorbent day tank	0	0	0	0	0
PTO N-645-12-4	Ash storage	0	0	0	0	0
PTO N-645-29-2	Emergency engine	88	0	9	28	10
PTO N-645-33-3	Emergency engine	219	0	15	47	18
ATC N-645-34-4	Cooling tower	0	0	80,665	0	292
ATC N-645-36-3	***Biomass-fired boiler***	***215,350***	***139,140***	***107,296***	***495,836***	***49,600***
ATC N-645-38-0	Fuel handling	0	0	107	0	0
ATC N-645-37-0	Fuel receiving	0	0	723	0	0
ATC N-645-39-0	Alternative fuel receiving					
ATC N-645-40-0	Biomass receiving	0	0	100	0	0
ERC	N/A	0	0	0	0	0
SSPE2		**215,657**	**139,140**	**188,937**	**495,911**	**49,920**

5. Major Source Determination

District Rule 2201 Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a Major Source is a stationary source with post-project emissions, or SSPE2 equal to or exceeding one or more of the following threshold values. However, Section 3.24.2 states, "for the purposes of determining major source status, the SSPE2 shall not include 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."

The major source determination is summarized in the below table:

Major Source Determination (lb/yr)					
	NO_x	**SO_x**	**PM_{10}**	**CO**	**VOC**
SSPE2	215,657	139,140	188,937	495,911	49,920
Major Source Threshold	50,000	140,000	140,000	200,000	20,000
Major Source?	**Yes**	No	**Yes**	**Yes**	**Yes**

As shown in the above table, this facility is a major source of NO_x, PM_{10}, CO and VOC emissions. This facility is not a major source of SO_x emissions.

Additionally, a major source of $PM_{2.5}$ is defined as one with the potential to emit 100 tons/yr (200,000 lb/yr) or more of $PM_{2.5}$. Since $PM_{2.5}$ is a subset of PM_{10} and PM_{10} emissions are less than 100 tons/yr, it is evident that SSPE2 for $PM_{2.5}$ emissions is also less than or equal to 100 tons/yr; thus, this facility is not a major source for $PM_{2.5}$.

District Rule 2410 Major Source Determination:

This facility will operate a biomass-fired power plant with a steam turbine, and associated biomass handling equipment. The appropriate PSD Major Source threshold is dependant on the source type. The following source types, from 40 CFR 52.21(b)(1)(iii) are subject to a 100 tons/year PSD threshold. All other source types are subject to a 250 tons/year PSD threshold.

a. Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input,
b. coal cleaning plants (with thermal dryers),
c. kraft pulp mills,
d. portland cement plants,
e. primary zinc smelters,
f. iron and steel mill plants,
g. primary aluminum ore reduction plants (with thermal dryers),
h. primary copper smelters,
i. municipal incinerators capable of charging more than 250 tons of refuse per day,
j. hydrofluoric, sulfuric, and nitric acid plants,
k. petroleum refineries,
l. lime plants,
m. phosphate rock processing plants,
n. coke oven batteries,
o. sulfur recovery plants,
p. carbon black plants (furnace process),
q. primary lead smelters,
r. fuel conversion plants,
s. sintering plants,
t. secondary metal production plants,
u. chemical process plants (which does not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140),
v. fossil-fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input,
w. petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels,
x. taconite ore processing plants,
y. glass fiber processing plants, and
z. charcoal production plants;
aa. Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

A closer examination of several of the above source categories is necessary to determine the appropriate PSD Major Source threshold.

Item "a", in the above list, states that fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input are one of the categories subject to a 100 ton/year PSD Major Source threshold. The proposed biomass plant is fired on both natural gas (during startup) and biomass. Natural gas is a fossil-fuel, while biomass is not a fossil-fuel. Since the 100 MMBtu/hr natural gas-fired burner is less than the 250 MMBtu/hr fossil-fuel fired threshold, this plant is not a fossil fuel fired steam electric plant of more than 250 MMBtu/hr.

Item "v", in the above list, states that fossil-fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input are subject to a 100 tons/year PSD Major Source Threshold. This is the only steam-fired boiler on-site and the rating is less than 250 MMBtu/hr when fired on fossil-fuel. Therefore, this plant is not a fossil-fuel boiler totaling more than 250 million British thermal units per hour heat input.

Item "aa", in the above list, states that any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act is subject to a 100 ton/year PSD Major Source Threshold. As of August 7, 1980, 40 CFR 60 Subparts D and Da were in place and potentially apply to the proposed unit. As demonstrated later in this evaluation, the proposed biomass plant is not subject to the requirements of Subparts D or Da and is not a stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	**VOC**	**SO_2**	**CO**	**PM**	**PM_{10}**
Facility PE	107.8	25.0	69.6	248.0	94.5	94.5
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

6. District Baseline Emissions (BE)

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22

The previous project for the conversion of the plant from a coal-fired power plant to a biomass-fired power plant resulted in offset requirements for PM10 and VOC emissions. The offset requirements were applied solely to the biomass-fired boiler ATC. In this project, the offset requirements will be revisited for the as-built plant revisions.

For NO_X:

The project to convert the facility from a coal-fired power plant into a biomass plant included the removal of two existing coal-fired boilers. In District project N-1101175, it was determined that offsets were provided for the full potential to emit of 215,350 lb-NOx/year for the two coal-fired boilers (N-645-29, and '-33), with additional offsets provided for the appropriate offset distance ratio. Therefore, the units are fully offset and BE is equal to PE1 for the removed units.

$BE_{NOx,\ removed\ units} = PE_{NOx,\ removed\ units} = 215{,}350$ lb/year

For SOx:

This facility is not a Major Source for SOx emissions; therefore, BE is equal to PE1. The two removed coal-fired boilers emitted SOx. Per the application review for District Project N-1101175,

$BE_{SOx,\ removed\ units} = PE_{SOx,\ removed\ units} = 228{,}490$ lb/year

For PM_{10}:

When this stationary source was originally permitted and constructed, POSDEF secured and surrendered offsets sufficient to mitigate 244 lb/day of PM_{10}. This quantity of offsets is equivalent to:

Offsets = (244 lb-PM_{10}/day) x (365 day/yr) = 89,060 lb/yr

Under Section 3.19.1 of Rule 2201, a unit may be considered fully offset if offsets have been provided for the unit's full potential to emit. When the facility was originally permitted, emissions from fuel handling equipment, the CFB boilers, limestone receiving and day use, and ash storage and loadout were calculated, for a total of 243.6 lb/day. Since 244 lb/day of offsets were provided, all units associated with the original permitting action (N-645-2, '-3, '-4, '-7, '-8, '-9, '-10, '-11, '-12, '-14, '-16, '-20, and '-23) were fully offset under Section 3.19.1 of the rule.

Of the remaining units, N-645-24 is a natural gas-fired auxiliary boiler with fuel oil #2 as a backup fuel. In accordance with Section 3.12.2 of Rule 2201, this boiler is a clean emission unit, defined as a unit equipped with BACT for that pollutant. However, this unit can only fire when one of the coal-fired combustors is not operating. Thus, including emissions from this unit would possibly be double counting PM10 emissions and the baseline emissions for this unit will be set equal to zero.

Unit N-645-31 is a fly ash reinjection operation which is required in order for the existing boilers to fire entirely on petroleum coke. It is noted that fly ash that is reinjected in a boiler simply becomes part of the boiler emissions, while potential emissions entrained in air from the pneumatic conveying system is routed to either the fly ash silo (with bin vent filter) or the boiler baghouse. Either of these controls is sufficient to qualify the fly ash reinjection operation as a clean emission unit under Section 3.12.2 of Rule 2201.

Unit N-645-35 is the emergency coal storage operation and reclaim conveyors. These units are served by baghouses, which normally have a minimum control efficiency of 99%. This exceeds the 95% control efficiency required under District Rule 2201, Section 3.12.1, so the emission units associated with the emergency coal storage operation and reclaim conveyors qualify as clean emission units under this provision.

The following table, obtained from the application review for District Project N-1101175, gives the baseline emissions for the units involved in the conversion of the plant from a coal-fired plant to a biomass-fired plant. The following table does not include the baseline emissions for units added during the conversion from coal to biomass, since baseline emissions for new units are equal to zero.

BE (lb/yr)	
Unit	**PM_{10}**
N-645-2-5	*219*
N-645-3-5	*37*
N-645-4-5	*37*
N-645-7-8	*183*
N-645-8-4	11
N-645-9-4	11
N-645-10-4	0
N-645-11-4	0
N-645-14-10	*43,800*
N-645-16-10	*43,800*
N-645-20-4	*0*
N-645-23-3	*0*
N-645-24-8	*0*
N-645-31-2	*0*
N-645-35-4	*1,570*
ΣBE	**89,668**

N/A: Not Applicable
Units in *italics* are existing units that will be removed from service as part of this project.

<u>For CO:</u>

This facility is a major source for CO emissions. However, BE is required for calculating the quantity of offsets required for those pollutants for which the offset requirement is triggered. As discussed in detail in the portion of this document devoted to District Rule 2201 offset requirements, this proposal is exempt from the requirement to provide CO offsets. Therefore, it is not necessary to determine BE for CO.

For VOC:

VOC emissions were only emitted by the two removed coal-fired combustors. The combustor permits only include a lb/hr VOC limit, which was based on the worst-case emission rate from all modes of operation, including startup and shutdown and periods where the units were only fired on fuel oil. The existing permits did not include a steady state emission limit. BACT Guideline 1.3.1 for a "Fluidized-Bed Combustor => 272 MMBtu/hr, Cogeneration Operation, Fired with Delayed Petroleum Coke" is applicable to the coal-fired combustors. The Achieved in Practice BACT requirement for VOC emissions from this Guideline is 0.008 lb-VOC/MMBtu, natural gas and fuel oil as auxiliary fuel. The following tables demonstrate that this unit has historically operated in compliance with the Achieved in Practice BACT limit during steady state operation of the coal-fired combustors. The units were placed into dormant status in 2009, and no testing data is available from that point forward.

Source Test Results for Unit N-645-14	
Test Date	**Recorded VOC Emission Rate**
November 13, 2008	0.001 lb/MMBtu
October 2, 2007	0.0067 lb/MMBtu
November 14, 2006	0.001 lb/MMBtu

Source Test Results for Unit N-645-15	
Test Date	**Recorded VOC Emission Rate**
November 13, 2008	0.002 lb/MMBtu
October 2, 2007	0.006 lb/MMBtu
November 14, 2006	0.003 lb/MMBtu

Since the coal-fired combustors have historically met the steady state Achieved in Practice BACT limit and the only auxiliary fuels used by these units are natural gas and fuel oil, the coal-fired combustors are clean for VOC emissions. The worst-case VOC potential to emit for these units, including startup and shutdown emissions and periods where the units are fired on auxiliary fuel, was calculated in District Project N-1101175, and is shown below:

$BE_{VOC,\ removed\ units} = PE_{VOC,\ removed\ units} = 43{,}800$ lb/year

7. SB288 Modification

Major Modification is defined in Title 40 Code of Federal Regulations Part 51.165 (40 CFR 51.165, as in effect December 19, 2002) as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*" The regulations further specify that the net emissions increase is calculated by comparing the potential emissions with the historical actual emissions for both the proposed modification itself.

The first issue to resolve for an SB288 Major Modification determination is that an SB288 Major Modification can only occur for a pollutant for which the facility is a major stationary source. As shown earlier in this evaluation, this facility is a Major Source for NO_x, PM_{10}, CO, and VOC emissions. However, it must be noted that there is no major modification threshold for CO in Rule 2201. Therefore, a major modification cannot be triggered for CO.

A project triggers an SB288 Modification if the project results in both a significant increase in emissions and a significant net emissions increase for a particular pollutant.

When determining if a project is a significant emission increase for a pollutant, only the increases in emissions associated with a project are considered. The increases in emissions are compared with the SB288 Modification threshold to determine if the project is a significant emissions increase for each pollutant.

Significant Increase in Emissions Determination			
Pollutant	**Emissions Increase from N-645-36-3 (lb/year)**	**SB288 Modification Threshold (lb/year)**	**Significant Increase in Emissions?**
NOx	215,350	50,000	**Yes**
PM10	107,296	30,000	**Yes**
VOC	49,600	50,000	No

As shown above, the NOx and PM10 emission increase alone triggers a significant increase in emissions. Thus, these pollutants must be further evaluated to determine whether the project also triggers a significant net emissions increase. The biomass-fired boiler is the only unit that emits VOC that is involved in this project and the project does not trigger a significant increase in emissions for VOC. Therefore, an SB288 Major Modification cannot be triggered for VOC emissions.

In order to determine whether the project is a significant net emission increase for NOx and PM10, the sum of the difference between the post-project potential to emit and the historical actual emissions from the modified/deleted units must be calculated. Pursuant to the District's draft Major Modification policy, the historical actual emissions may be set equal to the pre-project potential to emit for fully-offset emission units. Additionally, the contemporaneous emissions increases and decreases must be included for projects within the last five years; however, for this project it was determined that there is no contemporaneous increase or decrease in emissions within that timeframe

The following table shows the NOx significant net emission increase calculations and only includes units that emit NOx.

Significant Net Emission Increase Calculations for NOx			
Unit	**PE2**	**HAE**	**PE2 - HAE**
N-645-14-10	0	107,675[2]	-107,675
N-645-16-10	0	107,675[1]	-107,675
N-645-36-3	215,350	0	215,350
Total	**215,350**	**215,350**	**0**

The following table shows the PM10 significant net emission increase calculations and only includes units that emit PM10. Since the previous project includes the biomass handling units and dry-sorbent handling units, emissions from those units are included in the SB288 Modification Determination.

Significant Net Emission Increase Calculations for PM10			
Unit	**PE2**	**HAE**	**PE2 - HAE**
N-645-2-5	0	219[1]	-219
N-645-3-5	0	37[1]	-37
N-645-4-5	0	37[1]	-37
N-645-7-8	0	183[1]	-183
N-645-8-5	0	11[1]	-11
N-645-9-5	0	11[1]	-11
N-645-10-5	0	0	0
N-645-11-5	0	0	0
N-645-14-10	0	43,800[1]	-43,800
N-645-16-10	0	43,800[1]	-43,800
N-645-35-4	0	1,570[3]	-1,570
N-645-36-3	107,296	0	107,296
N-645-38-0	107	0	107
N-645-37-0 N-645-39-0	723	0	723
Total	**108,126**	**89,668**	**18,458**

Since the Significant Net Emission Increases for NOx and PM10 are less than the respective SB288 Major Modification Thresholds of 50,000 lb-NOx/year and 30,000 lb-PM10/year, this project does not trigger an SB288 Major Modification for NOx and PM10.

In summary, an SB288 Major Modification is not triggered by this project.

[2] This unit is fully-offset; therefore, HAE is equal to PE1 per the Districts Major Modification policy for SB288 Modifications.
[3] Historical Actual Emissions, per District Project N-1101175.

8. Federal Major Modification

Major Modification is defined in Title 40 Code of Federal Regulations Part 51.165 (40 CFR 51.165, as currently in effect) as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*" The regulations further specify that the net emissions increase is calculated by comparing the potential emissions with the historical actual emissions for both the proposed modification itself.

The first issue to resolve for a Federal Major Modification determination is that a Federal Major Modification can only occur for a pollutant for which the facility is a Major Source. As shown earlier in this evaluation, this facility is a Major Source for NO_x, PM_{10}, CO, and VOC emissions. However, it must be noted that there is no Federal Major Modification threshold for CO in Rule 2201. Therefore, a Federal Major Modification cannot be triggered for CO.

The next step is to determine whether this project will result in a significant increase in emissions. The increases in emissions are compared with the Federal Major Modification threshold to determine if the project is a significant emissions increase for each pollutant.

In order to determine the increase in emissions, it is necessary to determine whether the biomass plant is a new or existing emission unit. Pursuant to 40 CFR 51.165(a)(1)(vii)(B), a Replacement unit as defined in (a)(1)(xxi) is considered to be an existing emissions unit. 51.165(a)(1)(xxi) states the following: "*Replacement unit* means an emissions unit for which all criteria listed in paragraphs (a)(1)(xxi)(A) through (D) are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced." As shown below, the criteria of paragraphs (a)(1)(xxi)(A) through (D) are satisfied and the biomass plant qualifies as a Replacement unit.

Section 51.165(a)(1)(xxi)(A): The emissions unit is a reconstructed unit within the meaning of Section 60.15(b)(1) of this chapter, or the emissions unit takes the place of an existing emissions unit.

The biomass plant completely takes the place of the two existing coal-fired plants; therefore, Section 51.165(a)(1)(xxi)(A) is satisfied.

Section 51.165(a)(1)(xxi)(B): The emission unit is identical to or functionally equivalent to the replaced emissions unit.

The function of the existing coal-fired boilers was to generate steam and electricity. The biomass plant serves this same function; therefore, it is considered to be functionally equivalent and Section 51.165(a)(1)(xxi)(B) is satisfied.

Section 51.165(a)(1)(xxi)(C): The replacement does not alter the basic design parameters (as discussed in paragraph (h)(2) of this section) of the process unit.

Pursuant to 51.165(h)(2)(i), the basic design parameters for a process unit that is a steam electric generating facility are either:

1. *The maximum hourly heat input and maximum hourly fuel consumption rate;* ***or***
2. *The maximum hourly electric output rate and maximum steam flow rate.*

For this proposal, the maximum hourly electric output rate and the maximum steam flow rate will be chosen as the basic design parameters. The following table summarized the manufacturer's ratings for the basic design parameters, and demonstrates that no increase in the maximum hourly electric output rate and the maximum steam flow rate will result from replacing the existing coal fired boilers with the biomass boiler. Therefore, the basic design parameters are not changing and Section 51.165(a)(1)(xxi)(C) is satisfied.

Unit	***Maximum Hourly Electricity Output***	***Maximum steam flow rate***
Existing Coal Fired Boilers	*54 MW (Gross)*	*465,000 lb/hr*
New Biomass Boiler	*54 MW (Gross)*	*430,000 lb/hr*

Section 51.165(a)(1)(xxi)(D): The replaced emissions unit is permanently removed from the Major Stationary Source, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emission unit is brought back into operation, it shall constitute a new emissions unit.

The replacement coal fired boilers have been permanently removed from the Major Stationary Source. Section 51.165(a)(1)(xxi)(D) is satisfied.

Since the biomass boiler qualifies as a replacement unit, it will be treated as an existing emission unit.

For existing emission units, the Net Emissions Increase (NEI) is calculated as:

NEI = PAE – BAE, where:

PAE = Projected Actual Emissions
BAE = Baseline Actual Emissions

Net Emission Increase Calculation for NOx

NEI = PAE – BAE

According to the definition of projected actual emissions, the owner/operator may exclude, in calculating any increase in emissions that results from the project, the portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth. This excluded value will be denoted by the term "Unused Baseline Capacity".

For steam generating units, the baseline actual emissions (BAE) are equal to the average rate, in tons/year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the five year period preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority, whichever is earlier.

For this project, the owner/operator will utilize the 2007/2008 calendar year emission rates to determine the baseline actual emissions for the existing coal fired boilers, which is in the five year period prior to beginning actual construction in fall 2011.

2007 Combined NOx Actual Emissions = 130,560 lb-NOx
2008 Combined NOx Actual Emissions = 118,240 lb-NOx
BAE = Average Combined NOx Actual Emissions = 124,400 lb-NOx/year

The applicant is proposing to calculate the projected actual emissions as:

PAE = PE2 – UBC

PE2 is equal to the post-project potential to emit for the biomass boiler, which is 215,350 lb-NOx. The unused baseline capacity is the portion of the unit's emissions following the project that an existing unit could have accommodated during the 24-month baseline period. The existing coal fired boilers could accommodate up to 215,350 lb-NOx/year during the 24-month baseline period, but only accommodated 124,400 lb-NOx/year. Therefore, the portion the unit could have accommodated, but didn't, is 90,950 lb-NOx/year.

PE2 = 215,350 lb-NOx/year
UBC = 90,950 lb-NOx/year

NEI = PAE – BAE = (PE2 – UBC) – BAE
NEI = (215,350 lb-NOx/year – 90,950 lb-NOx/year) – 124,400 lb-NOx/year
NEI = 0 lb-NOx/year

The Federal Major Modification threshold is equal to zero for NOx emissions. Any increase greater than the threshold triggers a Federal Major Modification for NOx. Since the net emission increase is equal to zero for the project, a Federal Major Modification is not triggered for NOx emissions.

Net Emission Increase Calculation for PM10

NEI = PAE – BAE

According to the definition of projected actual emissions, the owner/operator may exclude, in calculating any increase in emissions that results from the
project, the portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth. This excluded value will be denoted by the term "Unused Baseline Capacity".

For steam generating units, the baseline actual emissions (BAE) are equal to the average rate, in tons/year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the five year period preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority, whichever is earlier.

For this project, the owner/operator will utilize the 2007/2008 calendar year emission rates to determine the baseline actual emissions for the existing coal fired boilers, which is in the five year period prior to beginning actual construction in fall 2011.

2007 Combined PM10 Actual Emissions = 55,520 lb-PM10
2008 Combined PM10 Actual Emissions = 35,920 lb-PM10
BAE = Average Combined PM10 Actual Emissions = 35,920 lb-PM10/year

The applicant is proposing to calculate the projected actual emissions as:

PAE = PE2 – UBC

PE2 is equal to the post-project potential to emit for the biomass boiler, which is 107,296 lb-PM10. The unused baseline capacity is the portion of the unit's emissions following the project that an existing unit could have accommodated during the 24-month baseline period. The existing coal fired boilers could accommodate up to 87,600 lb-PM10/year during the 24-month baseline period, but only accommodated 35,920 lb-PM10/year. Therefore, the portion the unit could have accommodated, but didn't, is 51,680 lb-PM10/year.

PE2 = 107,296 lb-PM10/year
UBC = 51,680 lb-PM10/year

NEI = PAE – BAE = (PE2 – UBC) – BAE
NEI = (107,296 lb-PM10/year – 51,680 lb-PM10/year) – 35,920 lb-PM10/year
NEI =19,969 lb-PM10/year

In addition to the NEI from the biomass boiler itself, an NEI for fuel handling equipment (N-645-37, '-38, '-39, and '40) of 930 lb-PM10/year, associated with the biomass boiler project, must be added, for a grand total NEI of 20,899 lb-PM10/year.

The Federal Major Modification threshold is equal to 30,000 lb-PM10/year for PM10 emissions. Any increase greater than the threshold triggers a Federal Major Modification for PM10. Since the net emission increase is less than 30,000 lb-PM10/year for the project, a Federal Major Modification is not triggered for PM10 emissions.

__Net Emission Increase Calculation for VOC__

NEI = PAE – BAE

According to the definition of projected actual emissions, the owner/operator may exclude, in calculating any increase in emissions that results from the project, the portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth. This excluded value will be denoted by the term "Unused Baseline Capacity".

For steam generating units, the baseline actual emissions (BAE) are equal to the average rate, in tons/year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the five year period preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority, whichever is earlier.

For this project, the owner/operator will utilize the 2007/2008 calendar year emission rates to determine the baseline actual emissions for the existing coal fired boilers, which is in the five year period prior to beginning actual construction in fall 2011.

2007 Combined VOC Actual Emissions = 23,622 lb-VOC
2008 Combined VOC Actual Emissions = 6,978 lb-VOC
BAE = Average Combined PM10 Actual Emissions = 15,300 lb-VOC/year

The applicant is proposing to calculate the projected actual emissions as:

PAE = PE2 – UBC

PE2 is equal to the post-project potential to emit for the biomass boiler, which is 49,600 lb-VOC. The unused baseline capacity is the portion of the unit's emissions following the project that an existing unit could have accommodated during the 24-month baseline period. The existing coal fired boilers could accommodate up to

43,800 lb-VOC/year during the 24-month baseline period, but only accommodated 15,300 lb-VOC/year. Therefore, the portion the unit could have accommodated, but didn't, is 28,500 lb-VOCyear.

PE2 = 49,600 lb-VOCyear
UBC = 28,500 lb-VOC/year

NEI = PAE – BAE = (PE2 – UBC) – BAE
NEI = (49,600 lb-VOC/year – 28,500 lb-VOC/year) – 15,300 lb-VOC/year
NEI =5,800 lb-VOC/year

The Federal Major Modification threshold is equal to zero for VOC emissions. Any increase greater than the threshold triggers a Federal Major Modification for VOC. Since the net emission increase is greater than zero for the project, a Federal Major Modification is triggered for VOC emissions.

Federal Offset Quantities

Actual emissions from the existing coal-fired boilers were determined for the period of time prior to their removal and replacement with the new biomass plant.

VOC		**Federal Offset Ratio**	**1.5**
Permit No.	**Actual Emissions (lb/year)**	**Potential Emissions (lb/year)**	**Emissions Change (lb/yr)**
N-645-36-3	**0**	**49,600**	**49,600**
N-645-14-13 and N-645-16-13	**15,300**	**0**	**-15,300**
		Net Emission Change (lb/year):	**34,300**
		Federal Offset Quantity: (NEC * 1.5)	**51,450**

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10

As shown earlier, this is not currently a Major Source for PSD.

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

As demonstrated earlier in this evaluation, neither the facility nor the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Total PE from New and Modified Units	107.8	25.0	69.6	248.0	94.5	94.5
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's Permit Administration System emissions profile screen. Detailed QNEC calculations are included in Appendix G.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

DTE proposes to remove from service both the existing CFB boilers and replace them with a single larger boiler connected to the same electrical generating equipment. This proposal obviously involves considerable capital expense and has the potential to qualify as a reconstruction of the stationary source. Pursuant to Section 3.33 of the rule, a reconstructed source is one in which the capital cost of any new components exceeds 50% of the fixed capital cost of a comparable, entirely new, stationary source. Such a reconstructed stationary source is evaluated as a new facility, rather than as a modification of an existing facility.

As shown in the capital cost analysis included in Appendix J, the fixed capital cost of the new components for the conversion project is estimated at $79,089,000. The estimated fixed capital cost of a new 50 MW biomass-fired electrical generating station is estimated at $211,347,000. The cost of new components is approximately 37% of the cost of a new facility, so the proposed conversion will not constitute a reconstructed stationary source.

A. Best Available Control Technology (BACT)

1. BACT Applicability

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

a. Any new emissions unit with a potential to emit exceeding 2.0 pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding 2.0 pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding 2.0 pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

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

a. New emissions units – PE > 2 lb/day

New Emissions Unit BACT Applicability for N-645-36-3				
Pollutant	**Daily Emissions (lb/day)**	**BACT Threshold (lb/day)**	**SSPE2 (lb/yr)**	**BACT Triggered?**
NO_X	2,225.2	> 2.0	n/a	**Yes**
SO_X	2,717.7	> 2.0	n/a	**Yes**
PM_{10}	833.8	> 2.0	n/a	**Yes**
CO	6,374.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	495,911	**Yes**
VOC	645.9	> 2.0	n/a	**Yes**

As shown above, BACT is triggered for NOx, SOx, PM10, CO, and VOC emissions. Additionally, ammonia is emitted by the biomass-fired power plant. However, ammonia emissions result from the use of ammonia in the selective catalytic reduction system, which is a control device and doesn't meet the definition of an emission unit. BACT is only applicable to emission units; therefore BACT for NH_3 from the control device is not required.

b. Relocation of emissions units – PE > 2 lb/day

There are no emissions units being relocated from one stationary source to another.

c. Modification of emissions units – AIPE > 2 lb/day

There are no modified emission units in this project to address the

d. Major Modification

This project is a Federal Major Modification for VOC emissions.

In summary, BACT is triggered for NOx, SOx, PM10, CO, and VOC emissions for the biomass-fired boiler.

2. BACT Guideline

A new BACT determination was created in District Project N-1101175 for biomass-fired boilers. A copy of that BACT determination is included in Appendix D.

3. BACT Determination

Pursuant to District Policy APR-1305, *Best Available Control Technology (BACT) Policy*, a top-down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements of District Rule 2201. As demonstrated in the Boiler BACT Determination (Appendix D), BACT is satisfied by:

NO_X: 0.065 lb/MMBtu using selective catalytic reduction
SO_X: 0.054 lb/MMBtu using trona injection
PM_{10}: 0.0214 lb/MMBtu using a multiclone and electrostatic precipitator
CO: 0.09 lb/MMBtu using an oxidation catalyst
VOC: 0.009 lb/MMBtu using an oxidation catalyst

B. Offsets

1. Offset Applicability

Emission offsets are required if SSPE2 equals or exceeds the following emission offset threshold levels for any one affected pollutant:

Emission Offset Thresholds (lb/yr)					
	NO_x	**SO_x**	**PM_{10}**	**CO**	**VOC**
SSPE1	215,657	228,490	170,357	693,502	44,120
SSPE2	215,657	139,140	188,937	495,911	49,920
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

As shown in the above table, the offset requirements are triggered for NO_x, SO_x, PM10, CO, and VOC. However, pursuant to Section 4.6.1 of the rule, increases in CO emissions in CO attainment areas may be exempt from offsets provided the applicant demonstrates that the increase will not result in an exceedance of the ambient air quality standard. Air quality monitoring conducted by the District has confirmed that this proposal qualifies for this exemption, so no further discussion of CO offsets is required.

2. Quantity of Offsets Required

As shown in Section VII.D.4, baseline emissions for NO_x, SO_x, PM_{10}, and VOC are equal to the pre-project potential to emit for each pollutant and each emission unit. In addition, it is noted that there are no cargo carriers serving this facility. The ERC certificates proposed for the offset package indicate the actual emission reductions that generated the offsets occurred more than 15 miles from the DTE facility, so the distance offset ratio for these pollutants is 1.5. The following tables summarize the PE, BE, and quantity of offsets required for the units involved in the project to convert this facility from a coal-fired plant to a biomass-fired plant. Note, unit N-645-40-0 was permitted separately, and the offset requirements for that unit were addressed in District Project N-1143459.

PE2 (lb/yr) for units in offset determination				
Unit	**NO_x**	**SO_x**	**PM_{10}**	**VOC**
N-645-8-5	0	0	11	0
N-645-9-5	0	0	11	0
N-645-10-5	0	0	0	0
N-645-11-5	0	0	0	0
N-645-36-3	215,350	139,140	107,296	49,600
N-645-38-0	0	0	107	0
N-645-37-0 N-645-39-0	0	0	723	0
ΣPE2	**215,350**	**139,140**	**108,148**	**49,600**

N-645-34-4 not included in PE2 because this unit is not undergoing a modification subject to NSR.

BE (lb/yr) for units in offset determination				
Unit	**NO_x**	**SO_x**	**PM_{10}**	**VOC**
N-645-2-5	*0*	*0*	*219*	*0*
N-645-3-5	*0*	*0*	*37*	*0*
N-645-4-5	*0*	*0*	*37*	*0*
N-645-7-8	*0*	*0*	*183*	*0*
N-645-8-4	0	0	11	0
N-645-9-4	0	0	11	0
N-645-10-4	0	0	0	0
N-645-11-4	0	0	0	0
N-645-14-10	*107,675*	*114,245*	*43,800*	*21,900*
N-645-16-10	*107,675*	*114,245*	*43,800*	*21,900*
N-645-20-4	*0*	*0*	*0*	*0*
N-645-23-3	*0*	*0*	*0*	*0*
N-645-24-8	*0*	*0*	*0*	*0*
N-645-31-2	*0*	*0*	*0*	*0*
N-645-35-4	*0*	*0*	*1,570*	*0*
N-645-36-3	0	0	0	0
N-645-38-0	0	0	0	0
N-645-37-0 N-645-39-0	0	0	0	0
ΣBE	**215,350**	**228,490**	**89,668**	**43,800**

Units in *italics* are existing units that have been removed from service as part of the conversion of the coal-fired power plant to a biomass-fired power plant.

Emission Offset Quantities Required (lb/yr)				
Pollutant	**ΣPE2 (lb/yr)**	**ΣBE (lb/yr)**	**ΣPE2 – ΣBE (lb/yr)**	**Total (lb/qtr)**
NO_x	215,350	215,350	0	0
SO_x	139,140	228,490	0†	0
PM_{10}	108,148	89,668	18,480	4,620
VOC	49,600	43,800	5,800	1,450

† Since BE is greater than PE2 this is less than 0. The project results in a decrease in emissions so the quantity of offsets required is 0.

The above table shows the quantity of offsets required, without the appropriate offset distance ratio. Since this project is a Federal Major Modification for VOC emissions, the appropriate offset distance ratio is 1.5. Additionally, the proposed particulate matter certificates were generated from emission reductions that occurred more than 15 miles from DTE; therefore, a 1.5 distance offset ratio also applies for PM10. The following table shows the quantity of ERC's required, at these distance offset ratios.

Quantity of Emission Reduction Credits Required (lb/yr)			
Pollutant	**Offsets Required (lb/qtr)**	**Distance Offset Ratio**	**Emission Reduction Credits Required (lb/qtr)**
PM_{10}	4,620	1.5	6,930
VOC	1,450	1.5	2,175

For PM10, the facility has proposed to use ERC Certificate N-1007-5 to satisfy the PM10 offset requirements for this project. ERC certificate N-1007-5 includes 27,720 lb/year of SOx offsets in Quarter 3. Pursuant to Section 4.13.6, actual emission reductions used as offsets for a biomass-fired power facility may have occurred during any quarter. Therefore, the offsets from ERC Certificate N-1007-5 may be equally distributed to the four quarters. Thus,

Quarterly ERC Certificates Available for SOx = 27,720 lb/year ÷ 4 quarters/year
Quarterly ERC Certificates Available for SOx = 6,930 lb/quarter

District Rule 2201 Section 4.13.3.1.2, interpollutant offsets between PM10 and PM10 precursors may be allowed. SOx is a precursor for PM10. Pursuant to the District's Draft Interpollutant Offset Ratio Explanation (see Appendix K), an interpollutant offset ratio of 1 lb-SOx for 1 lb-PM10 is applicable for this interpollutant trade.

Based on the 1:1 ratio, 6,930 lb/quarter of available SOx ERC's may be used to offset 6,930 lb/quarter of PM10. Since the quantity of Emission Reduction Credits proposed (6,930 lb/qtr) is equal to the quantity of emission reduction credits required in the previous table (6,930 lb/qtr), the applicant has proposed a sufficient quantity of ERC credits to offset the increases from this project for PM10.

The facility is proposing to utilize ERC Certificates S-4485-1 and S-3715-1 to satisfy the VOC offset requirements for this project. The table below demonstrates that the applicant has provided a sufficient quantity of ERC credits to meet the offset requirement of 2,175 lb-VOC/qtr.

VOC Emission Reduction Certificates Proposed				
Certificate	**Q1 (lb/qtr)**	**Q2 (lb/qtr)**	**Q3 (lb/qtr)**	**Q4 (lb/qtr)**
S-4485-1	725	725	725	725
S-3715-1	1,450	1,450	1,450	1,450
Total	**2,175**	**2,175**	**2,175**	**2,175**

The following conditions will be included on the boiler ATC to ensure compliance with the offset requirements of the rule:

- *Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits in the following quantities: 1st quarter – 6,930 lb, 2nd quarter – 6,930 lb, 3rd quarter – 6,930 lb, and 4th quarter – 6,930 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201]*

- *Prior to operating equipment under this Authority to Construct, the permittee shall surrender VOC emission reduction credits in the following quantities: 1st quarter – 2,175 lb, 2nd quarter – 2,175 lb, 3rd quarter – 2,175 lb, and 4th quarter – 2,175 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201]*

- *ERC Certificate Number N-1007-5 (or one or more certificates split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. The permittee is authorized to utilize SOx ERC to satisfy the PM10 offset obligation specified in this permit. The use of SOx ERC to satisfy the PM10 offset obligation shall be conducted at an interpollutant offset ratio of 1:1. [District Rule 2201]*

- *ERC Certificate Numbers S-3715-1 and S-4485-1 (or one or more certificates split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]*

C. Public Notice

1. Applicability

Pursuant to Section 5.4 of the rule, public notification and publication are required for the following types of applications:

5.4.1 New Major Sources, Major Modifications, and Federal Major Modifications

As shown in Section I, this is an existing facility and therefore cannot be a new major source. As shown in Sections VII.D.5 and 6, this proposal is a Federal Major Modification for VOC. A public notice is required under this provision.

5.4.2 Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one affected pollutant

As shown in Section VII.C.2, the proposed new boiler has the potential to emit more than 100 lb/day of NO_x, SO_x, PM_{10}, CO, and VOC. A public notice is required under this provision.

5.4.3 Modifications that increase SSPE1 from a level below the emissions offset threshold level to a level exceeding the emissions offset threshold level for one or more pollutants

While SSPE2 exceeds the emission offset threshold level for all pollutants, SSPE1 already exceeded the threshold. Public notice is not required under this provision.

5.4.4 New stationary sources with SSPE2 exceeding the emissions offset threshold level for one or more pollutants

As shown in Section I, this facility is not a new stationary source. Public notice is not required under this provision.

5.4.5 Any permitting action resulting in a Stationary Source Project Increase in Permitted Emissions (SSIPE) exceeding 20,000 pounds per year for any one pollutant

SSIPE (lb/yr)						
	NO_x	SO_x	PM_{10}	CO	VOC	NH_3
SSPE2	215,925	139,140	198,076	495,911	49,920	102,622
SSPE1	215,657	228,490	170,357	693,502	44,120	0
SSIPE = SSPE2 – SSPE1	0	< 0	27,719	0	5,793	102,622
SSIPE > 20,000?	No	No	**Yes**	No	No	**Yes**

As shown in the above table, SSIPE is greater than 20,000 lb/year for PM_{10} and NH_3. A public notice is required under this provision.

2. Public Notice Action

Public notice is required under Section 5.4 of the rule. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limitation (DEL)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO, and enforceable, in a practical manner, on a daily basis. DELs are also required to enforce the applicability of BACT. The following conditions will be included on the ATCs:

- *Startup is defined as the period of time beginning when the unit is heated to the operating temperature and pressure from a shutdown status or hot standby condition and ending only when the unit is firing on biomass or wood residue and is in compliance with the NOx, SOx, and CO emission limits for non-startup operation and with the minimum ESP secondary power input specified in this permit. [District Rules 2201 and 4352]*

- *Shutdown is defined as the period of time during which a unit is taken from operational to nonoperational status by allowing it to cool down from its operating temperature and pressure to an ambient temperature, or to a hot standby condition. Duration of shutdown shall not exceed 12 hours. [District Rules 2201 and 4352]*

- *Hot standby condition is defined as a condition in which all fuel feed has been curtailed and the boiler is secured at a temperature greater than the current ambient temperature. [District Rule 4352]*

- *Flame stabilization is defined as any period in which supplemental use of a liquid or gaseous fuel is required in instances including control of one or more pollutants, or to alleviate or prevent unanticipated equipment outages or emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. [District Rules 2201 and 4352]*

- *This unit shall only be fired on biomass and wood residue, except that the unit may also be fired on natural gas during startup, shutdown, and flame stabilization periods. [District Rules 2201 and 4102]*

- *Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.065 lb-NOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis as defined in District Rule 4352 (amended December 15, 2011). [District Rules 2201 and 4352]*

- *During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.74 lb-NOx/MMBtu. [District Rules 2201 and 4352]*

- *Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.09 lb-CO/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rules 2201 and 4352]*

- *During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.67 lb-CO/MMBtu. [District Rules 2201 and 4352]*

- *Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.054 lb-SOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rule 2201]*

- *During periods of startup, shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.27 lb-SOx/MMBtu. [District Rule 2201]*

- *Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.0214 lb-PM10/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201]*

- *During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.078 lb-PM10/MMBtu. [District Rule 2201]*

- *Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.009 lb-VOC/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201]*

- *During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.068 lb-VOC/MMBtu. [District Rule 2201]*

- *The ammonia slip emission rate from this biomass-fired boiler shall not exceed 40 ppmvd @ 3% O2. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201]*

- *Emissions from this biomass-fired boiler shall not exceed any of the following limits: 1st Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 2nd Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 3rd Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 4th Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC. Compliance with NOx, SOx, and CO limits shall be determined from CEM data. Compliance with PM10 and VOC limits shall be calculated using emission factors (the most recent source test results for non-startup/shutdown operation, or the startup/shutdown emission factors at all other times), heat input to the boiler, and operating time. [District Rule 2201]*[4]

- *HCl emissions from this biomass-fired boiler shall not exceed 19,980 pounds in any rolling 365 consecutive day period. HCl emissions shall be calculated daily for comparison to this annual limit using the daily boiler heat input determined pursuant to 40 CFR Part 75, Appendix F, Equation F-15 and the emission factor calculated in the most recent HCl source test. If HCl emissions from the biomass boiler, including emissions from startup, shutdown or malfunction periods are determined to have exceeded 19,999 pounds in any rolling 365-day period, the owner/operator shall submit an Authority to Construct application to comply with 40 CFR 63 Subpart DDDDDD requirements within 30 days of the exceedance. [District Rules 2201 and 4002]*

E. Compliance Assurance

1. Source Testing

The proposed biomass-fired boiler is subject to the source testing requirements of District Rule 4352, as well as various Federal requirements. The source testing requirements will be discussed in the portion of this document devoted to that rule. However, as shown in the discussion for District Rule 4002, the boiler is subject to various testing and record keeping requirements to ensure its status as an area source of hazardous air pollutants. The following conditions will be included on the ATC to ensure the validity of that conclusion:

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[4] Earlier in this evaluation, annual NOx and PM10 limits were presented. The quarterly emission limits enforces the annual NOx and PM10 limits.

- *This unit shall be tested to determine the HCl emission factor within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. The permittee shall measure and record the effluent pH and liquid flow rate in the wet scrubber every 15 minutes during the source test. [District Rule 2201]*

- *HCl emissions for source test purposes shall be determined using EPA Methods 26 or 26A, and 19. [District Rule 2201]*

2. Monitoring

The proposed biomass-fired boiler is subject to the monitoring requirements of District Rule 4352, various Federal requirements, and Compliance Assurance Monitoring. The monitoring requirements associated with those regulations will be discussed in the portion of this document devoted to those rules.

3. Continuous Emissions Monitoring (CEM)

CEM is required for NO_x, SO_x, CO, and O_2 under the provisions of District Rule 2540, *Acid Rain Program*, as described later in this document. The following conditions will be included on the ATC to ensure compliance:

- *The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, SOx, and CO2. Additionally, the exhaust stack shall be equipped with a flow monitor. The CEM shall meet the requirements of 40 CFR parts 60 (for CO) and 75 (for NOx, SOx, and CO2), except as specified in 40 CFR 60, Subpart Db, and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. The CEM shall be used to demonstrate compliance with the Rule 2201 emission limits. [District Rules 1080 and 2201]*

- *Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) in accordance with 40 CFR 60.48b, and 40 CFR 60 Appendices B and F. The sampling and analyzing cycle shall be completed every successive 10 second period, and the recording cycle shall be completed every successive 6 minute period. The COMS shall be used to demonstrate compliance with the opacity requirements of 40 CFR 43b(f) and (g). [District Rules 1080 and 2201, and 40 CFR 60.48b(a)]*

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

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

- *The 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 either an O2 or CO2 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]*

- *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]*

- *Permittee shall perform a relative accuracy test audit (RATA), as specified by 40 CFR Part 75, Appendix B, 2.3.1 for the NOx, SOx, and O2 or CO2 CEM,, at least once every two successive QA operating quarters (as defined in 40 CFR 72.2) unless the monitor satisfies the requirements for reduced RATA frequencies in Section 2.3.1.2. Permittee shall perform a RATA, as specified by 40 CFR Part 60, Appendix F for the CO CEM, at least once every four calendar quarters. Permittee shall perform a cylinder gas audit (CGA) or relative accuracy audit (RAA), as specified by 40 CFR Part 60, Appendix F for the CO CEM in three of four calendar quarters, but no more than three quarters in succession. The District must be notified at least 30 days prior to any RATA, and a test plan shall be submitted for approval at least 15 days prior to testing. The results of each RATA shall be submitted to the District within 60 days thereafter. [District Rule 1080]*

- *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 75, Appendix B. [District Rule 1080]*

- *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]*

- *When using measurements taken by the CO2 analyzer for emission compliance determinations, the following formula shall be used to convert the emission concentration referenced at 12 percent CO2 to an emission concentration referenced at 3 percent O2: E at 3%O2 = E at 12%CO2 x (CO2 F-Factor ÷ O2 F-Factor) x (100 ÷ 12) x (20.9 - 3) ÷ 20.9. Where, the CO2 F-Factor is in terms of scf CO2/MMBtu and the O2 F-Factor is in terms of dscf/MMBtu at 0% O2. Permittee may choose to use the default CO2 and O2 F-Factors for wood listed in 40 CFR Method 19, or may choose to use site-specific F-Factors. If using site specific F-Factors, permittee shall re-determine the site-specific F-Factors annually using at least 9 fuel samples. The site-specific F-Factors shall be determined in accordance with EPA Method 19. [District Rules 1080 and 2080, and 40 CFR 60]*

- *Permittee shall keep records of site-specific F-Factor determinations, including the date of each determination, the corresponding CO2 F-Factor, and the corresponding O2 F-Factor. [District Rules 1080 and 2080, and 40 CFR 60]*

4. Record Keeping

Records must be maintained in order to document compliance with all applicable rules and regulations. The biomass-fired boiler is subject to District Rule 4352, which includes applicable record keeping requirements, so those requirements will be discussed in the portion of this document devoted to that rule. In addition to the Rule 4352 recordkeeping requirements, the following recordkeeping requirement will be included on the Authority to Construct permit to ensure compliance with the quarterly emission limits:

- *Permittee shall maintain records of HCl emissions from this boiler on a rolling consecutive day basis. Records of HCl emissions shall be updated at least once each calendar day in which the boiler operates. [District Rule 2201]*

- *Permittee shall maintain records of HCl emissions from this boiler on a rolling 12-consecutive-month basis. Records of HCl emissions shall be updated at least once each calendar month in which the boiler operates. [District Rule 2201]*

- Permittee shall keep the results of the most recent source test, including the measure HCl emission rate and the applicable scrubber operating parameters, onsite. [District Rule 2201]

5. Reporting

The applicant is being granted a 24-month evaluation period in which to determine the optimum performance of the NO_x emission control system. During the evaluation period, annual status reports will be required. In addition, a final report will be required if the permittee has not been successful in demonstrating ongoing compliance with the design emission rate and will apply for an alternative emission limit. The following conditions will be included on the ATC to ensure compliance:

- *The permittee shall be allowed a 24-month period to evaluate the operational variability and optimum control effectiveness of the proposed exhaust emission control system to meet the design emission rate of 0.040 lb-NOx/MMBtu. During the evaluation period, the permittee shall operate and maintain the boiler and the emission control system in such a manner as to minimize NOx emissions, and shall perform all required source testing and monitoring. The evaluation period shall begin upon the first day of the initial source test, and shall terminate after 24 months. [District Rule 2201]*

- *During the 24-month evaluation period, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]*

- *During the 24-month evaluation period, the permittee shall submit annual status reports on the performance of the NOx emission control system. Each status report is due at the same time as the annual source test report. The status report shall, at a minimum, include actual operating time, actual heat input to the boiler, actual NOx emissions as measured by the CEM system, daily and annual average actual NOx emission rates (in lb/MMBtu), and an analysis of system performance to date and expected performance for the next year. [District Rule 2201]*

- *If NOx emissions continue to exceed, or are projected to exceed, 0.040 lbs/MMBtu on a block 24-hour average basis after the 24-month evaluation period, the permittee shall submit a final report containing all monitoring and source test data to the District within 90 days after the end of the evaluation period. The report shall include a detailed analysis of all factors that prevent achievement of the expected emission rate, as well as a detailed explanation of the steps taken to operate and maintain the boiler and the emission control system in such a manner as to minimize emissions. The report shall also propose an enforceable NOx emission limit, which shall not exceed 0.065 lb/MMBtu on a block 24-hour average basis. [District Rule 2201]*

- *Upon submittal of the report, the District shall re-evaluate BACT requirements for NOx from this class and category of source and establish an appropriate BACT emissions limit. Within 30 days of receipt of the District's determination, the permittee shall submit an Authority to Construct application to incorporate the revised emissions limit. In no case shall the NOx emission limitation be higher than 0.065 lbs/MMBtu on a block 24-hour average basis. [District Rule 2201]*

- *Following the 24-month evaluation period and prior to issuance of an Authority to Construct with a revised NOx emission limit, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]*

- *If NOx emissions do not exceed, and are not projected to exceed, the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis after the 24-month evaluation period, then the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis shall become an enforceable NOx emission limit. If the permittee fails to submit the required final report within 90 days after the end of the evaluation period, the permittee shall be considered to stipulate that an enforceable NOx emission limit of 0.040 lb/MMBtu on a block 24-hour average basis is achievable and will be made enforceable. [District Rule 2201]*

F. Ambient Air Quality Analysis

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to **Appendix E** of this document for the AAQA summary sheet.

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

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Title I Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Sections VIII-Rule 2201-C.1.a and VIII-Rule 2201-C.1.b, this facility is a major source and this project constitutes a Title I modification, therefore this requirement is applicable. DTE's compliance certification is included in Appendix H.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. A significant permit modification is defined as a "permit amendment that does not qualify as a minor permit modification or administrative amendment." Since this project triggers a Federal Major Modification for VOC emissions, the project cannot be considered a minor permit modification or administrative amendment. Therefore, the project is a significant permit modification and an EPA/public notice will be completed prior to issuing the Authority to Construct.

Rule 2540 Acid Rain Program

This rule incorporates by reference the Acid Rain Standards from 40 CFR 72 and, pursuant to §72.6(a)(3)(i), applies to new utility units, meaning any new fossil fuel-fired combustion device that serves a generator and is owned or operated by any person who sells electricity. Furthermore, the definition of "fossil fuel-fired" in §72.2 makes it clear than any combustion of fossil fuel, including natural gas, qualifies the unit as a fossil fuel-fired unit, independent of the percentage of fossil fuel consumed in any calendar year. Since the proposed boiler included in permit unit N-645-36-3 serves a 54 MW electrical generator, fires natural gas for startup and shutdown, and the electricity will be sold, this rule applies.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the latter of 1/1/2000 or the date the operator expects the unit to commence operation. The acid rain program requirements for this unit are expected to be minor. The owner will be required to monitor NO_x and SO_x emissions, to secure a fairly small quantity of SO_x allowances from a national SO_x allowance bank, and to install NO_x and SO_x CEMS; conditions requiring installation and operation of NO_x and SO_x CEMS are already included in the boiler ATC. DTE submitted the acid rain application on December 6, 2010. No further discussion is required.

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

This rule applies to any application to construct or reconstruct a major source of air toxics, defined as a facility with the potential to emit 10 tons per year or more of any one hazardous air pollutant (HAP), or 25 tons per year or more of all HAP combined. DTE will not be a major source of HAP following the proposed modification to the facility, because HCl emissions shall not exceed 9.99 ton/yr, so this rule does not apply. No further discussion is required.

Rule 4001 New Source Performance Standards (NSPS)

40 CFR 60 Subpart D – Standards of Performance for Fossil-Fuel Fired Steam Generators and 40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

It was determined in District Project N-1101175 that Subparts D and Da are not applicable to the biomass-fired boiler since the maximum heat input rate from fossil fuels is less than 250 MMBtu/hr for this unit.

40 CFR 60 Subpart Db – Standards of Performance for Electric Utility Steam Generating Units

Pursuant to 40 CFR 60.40Da(a)(1), this subpart is applicable to each electric utility steam generating unit that is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone, or in combination with any other fuel) and that is constructed, modified, or reconstructed after September 18, 1978. Since the fossil-fuel fired startup burner in this project is rated at 100 MMBtu/hr, this unit is not capable of combusting more than 250 MMBtu/hr heat input of fossil fuel and

40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The biomass-fired boiler is subject to the requirements of 40 DFR 60 Subpart Db, since the heat input capacity from fuels combusted is greater than 100 MMBtu/hr. Compliance with this regulation was evaluated in District Project N-1101175, and that determination is not changing as a result of the as-built changes proposed in this project. The following conditions will be included on the Authority to Construct to ensure compliance:

- *The total annual heat input to the unit from natural gas combustion shall not exceed 612,324 MMBtu in any one calendar year. [District Rules 4001 and 40 CFR 60.44b(d)]*

- *Permittee shall record the heat input to the unit from each fuel combusted on a daily basis. Permittee shall maintain records of the annual capacity factor for each fuel combusted on a 12-month rolling average basis, and shall update the annual capacity factor for each fuel at the end of each calendar month. [District Rules 1070 and 4001, and 40 CFR 60.49b(d)(1)]*

- *Permittee shall retain and maintain on site all data from the continuous opacity monitoring system. [District Rules 1070 and 4001, and 40 CFR 60.39b(f)]*

40 CFR 60 Subpart CCCC – Standards of Performance of Commercial and Industrial Solid Waste Incineration Units

40 CFR 60.2020(e) states that small power production facilities that meet the following requirements are exempt from Subpart CCCC:

1. The unit qualifies as a small power-production facility under section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C).
2. The unit burns homogeneous waste (not including refuse-derived fuel) to produce electricity.
3. The facility submits documentation to the Administrator notifying EPA that the qualifying small power production facility is combusting homogeneous waste.
4. The facility maintains the records specified in 40 CFR 60.2175(w).

DTE Stockton states that they are a small power-production facility and will comply with the above requirements. The following recordkeeping requirement will be included on the Authority to Construct permit:

- *The permittee shall maintain records of the criteria used to establish that the unit qualifies as a small power production facility under section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)) and that the waste material the unit is proposed to burn is homogeneous (not including refuse-derived fuel). [40 CFR 60.2175(w)]*

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

40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This subpart is applicable to new, reconstructed, and existing industrial, commercial, institutional boilers, or process heaters located at a Major Source of HAP emissions. A Major Source of HAP emissions is any facility with a potential to emit, considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

As shown by the data included in Appendix F of this document, DTE will have potential emissions of 9.99 tons per year (tpy) for any single HAP (specifically, HCl), and 15.7 tons per year for all HAP combined. Therefore, DTE is not a Major Source of HAP emissions; rather, DTE is an area source of HAP emissions. Subpart DDDDD requirements are not applicable to the biomass-fired boiler.

40 CFR 63 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The biomass-fired boiler is located at an area source of HAP emissions; therefore, Subpart JJJJJJ requirements are applicable to the biomass-fired boiler. 40 CFR 63 Subpart JJJJJJ was evaluated in District Project N-1101175. The changes proposed in this project do not affect that determination. The following conditions will be included on the Authority to Construct to ensure compliance:

- *The permittee shall conduct a performance tune-up of the boiler in accordance with the requirements of 40 CFR 63 Subpart JJJJJJ within 180 days of initial startup, and at least every 24 months thereafter. The permittee shall submit a signed statement in the Notification of Compliance Status indicating that each tune up was conducted. [40 CFR 63.11210]*

- *Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.030 lb-PM/MMBtu [40 CFR 60.43b(h)(1) and 40 CFR 63.11201]*

- *This unit shall be tested for compliance with the PM emission limit within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 36 months thereafter. [40 CFR 60.8(a), 40 CFR 60.43b(d), and 40 CFR 63.11220(a)]*

- *PM emissions required to be source tested under condition 55 shall be determined using EPA Methods 5 or 17 (filterable (front half) PM only), and 19. [40 CFR 60.43b(d)(2) and 40 CFR 63.11212]*

- *The electrostatic precipitator shall be provided with continuous monitoring equipment showing the secondary power input, as specified in 40 CFR 63, Subpart JJJJJJ. The monitoring equipment shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201 and 40 CFR 63.11224]*

- *The electrostatic precipitator shall be in operation whenever the boiler is operated on biomass. The electrostatic precipitator secondary power input, on a 12-hour block average, shall be maintained at or above the lowest 1-hour average secondary power input measured during the most recent performance test demonstrating compliance with the PM emission limitation, in accordance with Table 3 of 40 CFR 63, Subpart JJJJJJ. Transient voltage fluctuations due to arcs and sparks, or similar automatic functions of the electrostatic precipitator, shall not constitute deviations. The electrostatic precipitator shall be maintained in accordance with the manufacturer's recommendations, a copy of which shall be maintained on site. [District Rule 2201, 40 CFR 63.11221 and 40 CFR 64]*

As stated above, DTE is an area source of hazardous air pollutants. However, this area source status is based on a voluntary limit of 9.99 tons per year for HCl emissions. Compliance with this emission limit will be demonstrated through a combination of source testing and record keeping, as outlined in the above conditions. However, to ensure that the use of source testing emission factors is representative of actual HCl emissions over the remainder of the year, a monitoring program for the wet HCl scrubber is appropriate. While not subject to 40 CFR 63 Subpart DDDDD, 40 CFR 63 Subpart DDDDD would require monitoring of the wet scrubber pH, reducing the data to a 30-day rolling average. The District will use this guidance from 40 CFR 63 Subpart DDDDD to establish an appropriate monitoring plan for the scrubber.

The following conditions will be included on the ATC:

- *The wet scrubber shall be provided with monitoring equipment that continuously monitors and records the effluent pH and flow rate of the scrubber liquid. [District Rule 2201]*

- *The wet scrubber shall be in operation whenever the boiler is operated on biomass. The effluent pH and liquid flow rate, calculated on a rolling 30-day average basis, shall be maintained at or above the average pH and flow rate established during the most recent HCl source test. [District Rules 2201 and 4002] Y. [District Rules 2201 and 4002]*

Rule 4101 Visible Emissions

This rule defines and regulates visible emissions from any source operation. In addition, opacity from the boiler stack is limited by 40 CFR 60.43b(f). The following condition will be included on the ATC to ensure compliance:

- *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 and 40 CFR 60.43b(f) and (g)]*

Rule 4102 Nuisance

This rule prohibits the emission of any pollutant that results in nuisance, injury, detriment, or annoyance to any significant number of persons. The following condition will be included on the ATC to ensure compliance:

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

California Health & Safety Code 41700 (Health Risk Assessment)

Pursuant to District policy APR-1905, *Risk Management Policy for Permitting New and Modified Sources*, the District must conduct a health risk assessment for any increase in affected pollutant or HAP emissions.

The as-built revisions will not result in an increase in risk from the previous RMR conducted in District Project N-1101175. Therefore, the previous RMR is still valid for the biomass-fired boiler. The following table shows the RMR summary for the biomass-fired boiler.

RMR Summary (see full results in Appendix E)			
Categories	**Stoker-Fired Biomass Boiler (Unit 36-3)**	**Project Totals**	**Facility Totals**
Prioritization Score	409	>1.0	>1.0
Acute Hazard Index	0.0	0.0	0.0
Chronic Hazard Index	0.2	0.0	0.0
Maximum Individual Cancer Risk (10^{-6})	8.54[2]	8.54	8.54
T-BACT Required?	**Yes**		
Special Permit Conditions?	**No**		

1 Risks for Units 37-0 and 38-0 are included in the risk estimate for Unit 36-3. Unit 39-0 has HAP emissions equal to or less than unit 37-0, and since the two units are mutually exclusive no further analysis is required.
2 Risk at the Point of Maximum Impact.

As shown in the table above, the proposed facility will have acute and chronic hazard indices below the significance thresholds of 1. The proposed facility will have a cancer risk between 1 and 10 in a million, and will therefore trigger T-BACT for PM_{10} emissions. As shown in the discussion of BACT under Rule 2201 above, BACT is satisfied by DTE's proposal to use a multiclone and ESP to reduce the PM_{10} emission rate to 0.0214 lb/MMBtu. Pursuant to APR-1905, T-BACT is satisfied by BACT for the pollutants that trigger T-BACT; since DTE has proposed BACT for PM_{10}, the T-BACT requirements are also satisfied. The following special permit conditions will be included on the boiler ATC to ensure the validity of this analysis:

- *The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]*

- *This unit shall only be fired on biomass and wood residue, except that the unit may also be fired on natural gas during startup, shutdown, and flame stabilization periods. [District Rules 2201 and 4102]*

- *Biomass is defined as any organic material originating from plants, not chemically treated and not derived from fossil fuels, including but not limited to products, by-products, and residues from agriculture, forestry, aquatic and related industries, such as agricultural, energy or feed crops and residues, orchard and vineyard prunings and removal, stone fruit pits, nut shells, cotton gin trash, corn stalks and stover, straw, seedhulls, sugarcane leavings and bagasse, aquatic plants and algae, cull logs, eucalyptus logs, poplars, willows, switchgrass, alfalfa, bark, lawn, yard and garden clippings, paper (unprinted), leaves, silvicultural residue, tree and brush pruning, sawdust, timber slash, mill scrap, wood and wood chips, and wood residue. Biomass does not include tires, material containing sewage sludge, or industrial, hazardous, radioactive, or municipal solid waste. [District Rules 2201 and 4102]*

- *Wood residue consists of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. [District Rules 2201 and 4102]*

- *Biomass and wood waste fuels shall not include pressure-treated wood and shall not contain compounds listed in Title 22, California Code of Regulations, 66261.24(a)(2)(A) in excess of the following concentrations by weight: 500 ppm antimony and/or antimony compounds, 500 ppm arsenic and/or arsenic compounds, 1,000 ppm asbestos, 10,000 ppm barium and/or barium compounds (excluding barite), 75 ppm beryllium and/or beryllium compounds, 100 ppm cadmium and/or cadmium compounds, 500 ppm chromium (VI) compounds, 2,500 ppm chromium and/or chromium (III) compounds, 8,000 ppm cobalt and/or cobalt compounds, 2,500 ppm copper and/or copper compounds, 18,000 ppm fluoride salts, 1,000 ppm lead and/or lead compounds, 20 ppm mercury and/or mercury compounds, 3,500 ppm molybdenum and/or molybdenum compounds, 2,000 ppm nickel and/or nickel compounds, 100 ppm selenium and/or selenium compounds, 500 ppm silver and/or silver compounds, 700 ppm thallium and/or thallium compounds, 2,400 ppm vanadium and/or vanadium compounds, and 5,000 ppm zinc and/or zinc compounds. [District Rule 4102 and 22 CCR 66261.24]*

- *Permittee shall test fuel for contaminants within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter, or whenever requested by the District. The District shall be notified at least 15 days prior to scheduled sample collection. [District Rules 2201 and 4102, and 40 CFR 60.8(a)]*

- *Testing of the fuel for contaminants shall be conducted on a representative sample collected upstream of and as close as practicable to the fuel metering bins. [District Rules 2201 and 4102]*

- *Fuel shall be tested for contaminants in accordance with the wet extraction test procedure detailed in Title 22 California Code of Regulations, Division 4.5, Chapter 11, Appendix II. [District Rule 4102]*

Rule 4201 Particulate Matter Concentration

This rule prohibits emissions of particulate matter (PM) from any source operation in excess of 0.1 grains per dry standard cubic foot of exhaust gas.

The combination of a multiclone and ESP is expected to ensure that the emission rates for PM and PM_{10} from the boiler are essentially identical. The particulate matter concentration for the boiler when operating at a limit of 0.078 lb/MMBtu during startup and shutdown is calculated as follows:

C = (0.078 lb-PM/MMBtu) x (7,000 gr/lb) ÷ (9,240 dscf/MMBtu)
C = 0.059 gr/dscf

Since 0.059 gr/dscf is less than the rule limit of 0.1 gr/dscf, the boiler is expected to comply with this rule requirement. The following condition will be included on the ATC to ensure compliance with this rule:

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

Rule 4202 Particulate Matter Emission Rate

This rule prohibits particulate matter emissions from any source operation in excess of the prescribed limits in proportion to the process weight rate. Compliance was demonstrated in District Project N-1101175. The as-built changes in this project will not affect that determination. Continued compliance is expected. The following condition will be included on the ATC to ensure compliance:

- *Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202]*

Rule 4203 Particulate Matter Emissions from Incineration of Combustible Refuse

This rule limits particulate matter emissions from any operation that disposes of or processes combustible refuse by burning. Rule 1020 (Definitions) defines combustible refuse as "any solid or liquid combustible waste material containing carbon in a free or combined state." While biomass meets this definition in other particulars, it is actually a byproduct of agricultural operations rather than a "waste" material. Nonetheless, this unit will comply with the rule limits.

The rule provides for two particulate matter grain loading limitations, one of which applies to any process with a burn rate in excess of 100 pounds per hour and the other of which applies to any process with a burn rate less than or equal to 100 pounds per hour. Alternatively, the operator may comply with a mass emission limit of 0.10 pounds per 100 pounds of combustible refuse burned. For a unit combusting 100 lb/hr of fuel or more, the grain loading limit is 0.10 gr/dscf calculated to 12% CO_2.

The grain loading concentration (C) for the boiler during startup and shutdown is equal to:

$C = (0.078 \text{ lb-PM}_{10}/\text{MMBtu}) \times (7{,}000 \text{ gr/lb}) \times (1 \text{ MMBtu}/1{,}830 \text{ dscf}) \times (0.12 \div 1.0)$
$C = 0.036 \text{ gr/dscf}$

Since 0.036 gr/dscf is less than the rule limit of 0.10 gr/dscf, compliance with the PM_{10} DEL will ensure compliance with this rule. No further discussion is required.

Rule 4301 Fuel Burning Equipment

This rule regulates emissions of NO_x, SO_x, and PM from any process that burns fuel for the production of heat or power by indirect heat transfer. These limits are 140 lb/hr for NO_x, 200 lb/hr for SO_x, and 10 lb/hr for PM, which is also subject to a grain loading limit of 0.1 gr/dscf calculated to 12% carbon dioxide.

Compliance with these requirements was demonstrated in District Project N-1101175. The as-built changes in this project will not affect the previous determination. Continued compliance with the District Rule 4301 requirements is expected.

Rule 4304 Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters

This rule specifies the tuning procedure for boilers that require tuning under other District rules. However, the only applicable District boiler rule does not have any tuning requirements. This rule does not apply, and no further discussion is required.

Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2
Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3
Rule 4320 Advanced Emission Reduction Operations for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr
Rule 4351 Boilers, Steam Generators, and Process Heaters – Phase 1

Each of these rules applies to boilers with heat input ratings in excess of 5.0 MMBtu/hr; however, each rule also includes an exemption for solid fuel-fired boilers. No further discussion is required.

Rule 4352 Solid Fuel Fired Boilers, Steam Generators, and Process Heaters

This rule applies to any solid fuel-fired boiler and is intended to regulate NO_x and CO emissions during steady-state, startup, shutdown, and flame stabilization operating periods. Section 4.0 of the rule provides an exemption, except from the record keeping requirements, for any unit located at a facility with stationary source potential emissions less than 10 ton/yr (20,000 lb/yr) of NO_x or VOC. As shown in Section VII.D.2, SSPE2 at this facility exceeds 20,000 lb/yr for both NO_x and VOC, so the Section 4.0 exemption does not apply.

Section 5.1 specifies the emission limits for various types of solid fuel-fired boilers. Separate categories are provided for units firing municipal solid waste or multiple hearth furnaces firing biomass, but the proposed stoker-type unit does not fall into either of these categories. The rule emission limits, along with the emission limits for the proposed unit, are summarized in the below table:

Rule 4352 Emission Limits (ppmv)		
	NO_x	CO
Rule 4352 Limit	90	400
Proposed Unit, Steady-State	49.7	113
Rule 4352 Compliant?	Yes	Yes

All emission limits corrected to 3% O_2.

The proposed NO_x and CO emission factors are converted to exhaust gas concentrations corrected to 3% O_2 as follows:

C_{NOx} = (0.065 lb/MMBtu) ÷ [(46 lb/lb-mol) x (9,240 ft^3/MMBtu) x (20.95 ÷ (20.95 – 3.00)) ÷ (379.5 ft^3/lb-mol)] x 10^6
C_{NOx} = 49.7 ppmv @ 3% O_2

C_{CO} = (0.09 lb/MMBtu) ÷ [(28 lb/lb-mol) x (9,240 ft^3/MMBtu) x (20.95 ÷ (20.95 – 3.00)) ÷ (379.5 ft^3/lb-mol)] x 10^6
C_{CO} = 113 ppmv @ 3% O_2

Note that the emission factor of 0.065 lb-NO_x/MMBtu used above is the firm short-term emission limit. Compliance with the expected emission rate of 0.040 lb-NO_x/MMBtu will also result in compliance with the Rule limit. Section 5.2 of the rule provides that compliance with the rule emission limits shall be demonstrated on a block 24-hour average basis.

Section 5.3 of the rule provides for limited exemptions to the Section 5.1 emission limits during startup and shutdown periods. Section 5.3.1 limits each shutdown to 12 hours duration, while Section 5.3.2 limits a startup to 96 hours duration unless curing the refractory material. DTE has proposed a maximum of 12 hours of startup and shutdown per day, which complies with the rule limits, and total of 24 hours of startups and shutdowns per year. However, emissions during startup and shutdown will be limited by a flat mass limit on daily emissions along with a heat input-based emission limit expressed in lb/MMBtu, rather than by an explicit time limit on startup and shutdown operation.

Section 5.4 of the rule describes the monitoring requirements. This section requires that any unit using an ammonia injection system to install, calibrate, and maintain in operation a NO_x CEM. This unit is required to have a NO_x CEM by various other provisions and rule requirements, which will also ensure compliance with this section of the rule.

Section 6.1.1 states that the owner/operator of any unit subject to the requirements of Rule 4352 must maintain, on a monthly basis, an operating log for each unit that includes the type and quantity of fuel used and the higher heating value of each fuel, as determined by Section 6.3, or as certified by a third party fuel supplier. Additionally, the permitee will be required to keep records of the date and duration of start-up and shutdown periods and records of fuel contaminant testing results. The following conditions will be included on the boiler ATC to ensure compliance:

- *Permittee shall maintain records of the date and duration of start-up and shutdown periods. [District Rules 2201 and 4352]*

- *Permittee shall maintain, on at least a monthly basis, an operating log that includes the type and quantity of fuel used, and the higher heating value of each fuel, as determined by Section 6.3 of District Rule 4352 (12/15/11), or as certified by a third party fuel supplier. [District Rules 1070 and 4352]*

Section 6.1.2 requires records to be retained on site for a period of five years. The following condition will be included on the boiler ATC to ensure compliance:

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 2201 and 4352]*

Sections 6.2 and 6.3 of the rule detail the source testing requirements test methods used to demonstrate compliance with the rule requirements. The following conditions will be included on the boiler ATC to ensure compliance:

- *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 shall be submitted for approval at least 15 days prior to testing. [District Rule 1081]*

- *The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]*

- *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 1081 and 2201]*

- *This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)]*

- *This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits within 60 days of achieving the maximum steam production rate, but no more than 180 days after initial startup, and at least once every 12 months thereafter. The PM source test required by condition 55 may be conducted in lieu of PM10 testing required by this condition, provided all PM is assumed to be PM10 as specified in condition 64. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)]*

- *NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or ARB Method 100 and EPA Method 19. [District Rules 1081 and 4352]*

- *CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 1081 and 4352]*

- *PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352]*

- *In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081]*

- *Stack gas oxygen shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 1081 and 4352]*

- *SOx emissions for source test purposes shall be determined using EPA Method 6 or ARB Method 100. [District Rules 1081 and 4352]*

- *VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rules 1081 and 4352]*

- *Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rules 1081 and 2201]*

- *Testing for fuel higher heating value shall be conducted using ASTM Method D5865-01a or District-approved equivalent method. [District Rules 1081 and 4352, and 40 CFR 75 Appendix F]*

Rule 4801 Sulfur Compounds

This rule prohibits the emission of sulfur compounds in excess of 2,000 ppmv as sulfur dioxide (SO_2). The potential concentration of SO_x in the combustor exhaust gas during startup and shutdown, which represents the worst-case SOx emission rate, can be calculated as follows:

C = (0.27 lb-SO_x/MMBtu) x (1 lb-mol/64 lb-SO_x) x (379.5 ft^3/lb-mol) ÷ (9,240 ft^3/MMBtu) x 10^6
C= 173 ppmv

Since 173 ppmv is less than the rule limit of 2,000 ppmv, compliance with the rule is expected. No further discussion is required.

40 CFR 64 Compliance Assurance Monitoring

The boiler will be evaluated in detail for the CAM requirements. No other emission unit has any potential to require CAM based on uncontrolled emissions, so no further discussion of CAM for any other emission unit is required.

Pursuant to 40 CFR 64.2(a), CAM is required (on a pollutant-by-pollutant basis) for an emission unit that is subject to an emission limit, is equipped with an add-on control for compliance with that emission limit, and which has potential pre-control emissions equal to or greater than the major source threshold. The boiler is subject to an emission limit for each affected pollutant, and is also equipped with an add-on control device for each pollutant. Controlled and pre-controlled emissions are calculated in the following table for comparison with the applicable major source thresholds.

Compliance Assurance Monitoring (lb/yr)					
Unit	**NO_x**	**SO_x**	**PM_{10}**	**CO**	**VOC**
N-645-36-3, PE2	215,618	139,140	107,296	495,836	49,600
Major Source Threshold	50,000	140,000	140,000	200,000	50,000
CAM required?	Yes	No	No	Yes	No
Control efficiency		80%	99%		47%[5]
Pre-controlled PE2[6]		695,700	10,729,600		93,585
Major Source Threshold		140,000	140,000		50,000
CAM required?		Yes	Yes		Yes

Controlled emissions of NO_x and CO already exceed the major source threshold, so there is no need to calculate the pre-control potential emissions for these pollutants. For SO_x, PM_{10}, and VOC pre-control potential emissions are calculated and shown to exceed the major source threshold. Therefore, CAM is required for the boiler for all pollutants.

[5] Per letter from Süd-Chemie regarding oxidation catalyst performance for control of non-methane, non-ethane hydrocarbons, dated October 19, 2010.
[6] In each case uncontrolled PE2 is calculated by dividing PE2 by the quantity (1 – control efficiency).

In accordance with §64.3(d), a CEMS or continuous opacity monitoring system (COMS) that is required by another section of the federal regulations under the Clean Air Act may be used to satisfy the CAM requirement for the pollutant being monitored. This boiler will be equipped with CEMS for NO_x, SO_x, and CO as required by 40 CFR 75, so CAM will be satisfied for those pollutants by the use of CEMS. No further discussion of CAM for NO_x, SO_x, and CO is required.

This boiler is subject to the CAM requirement for VOC. VOC emissions are generally related to CO emissions, since both are the result of incomplete combustion and both are affected by the same pollution controls. The applicant has proposed to use the CO CEMS to satisfy the CAM requirement for VOC, on the grounds that both pollutants have the same origin and are controlled by the same technologies. District experience with oxidation catalysts (such as those installed on turbines) suggests that it is difficult to establish a direct correlation between CO and VOC emissions that would allow calculation of actual VOC emissions based on actual CO emissions measured by the CEMS. Nonetheless, it is true that an oxidation catalyst that is operating properly to control CO will also be operating to control VOC. Furthermore, as discussed in the portion of this document devoted to District Rule 4352, the applicant will be required to conduct annual source testing to demonstrate compliance with the boiler emission limits for both VOC and CO, and the source testing data is expected support the conclusion that compliance with the CO emission limit strongly suggests the unit is also in compliance with the VOC limit. Therefore, the use of CEMS to satisfy the CAM requirement for CO will be considered to also satisfy the CAM requirement for VOC. No further discussion is required.

The applicant has proposed to monitor secondary power input to the ESP to satisfy the CAM requirement for PM_{10}. This monitoring is also required for compliance with 40 CFR 63, Subpart JJJJJJ and was discussed in the portion of this document devoted to that Subpart and District Rule 4002.

California Environmental Quality ACT (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The Port of Stockton (Port) is the public agency having principal responsibility for approving the Project. As such, the Port served as the Lead Agency for the project and filed a Notice of Exemption with the Office of Planning and Research and San Joaquin County on March 23, 2011. Consistent with CEQA Guidelines §15329 (Class 29 – Cogeneration Projects at Existing Facilities) and §15302 (Class 2 – Replacement or Reconstruction), a Notice of Exemption was prepared and certified by the Port.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381).

The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's thresholds of significance for criteria pollutants. Thus, the District concludes that through a combination of project design elements and permit conditions, project specific stationary source emissions will be reduced and mitigated to less than significant levels. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending satisfactory completing of the required NSR and COC notice periods, issue Authority to Construct N-645-36-3 subject to the conditions on the attached draft Authority to Construct in Appendix A.

X. Billing Information

Billing Information			
Permit Number	**Previous Fee Schedule**	**Fee Schedule**	**Description**
N-645-36-3	N/A	3020-08B-G	54,000 kW

Appendices

Appendix A: Draft Authority to Construct
Appendix B: Authorities to Construct from District Project N-1101175
Appendix C: Permits to Operate for the Coal-Fired Power Plant
Appendix D: Boiler BACT Determination from District Project N-1101175
Appendix E: Health Risk Assessment and Ambient Air Quality Analysis
Appendix F: Hazardous Air Pollutant Emissions
Appendix G: QNEC Calculations
Appendix H: Compliance Certification
Appendix I: Original POSDEF Offset Evaluation
Appendix J: Reconstructed Source Analysis
Appendix K: Draft Interpollutant Offset Policy
Appendix L: Comments from Center for Biological Diversity and District Response

Appendix A
Draft Authority to Construct

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

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PERMIT NO: N-645-36-3 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: ATTN: PAYABLE DEPARTMENT
2526 W WASHINGTON ST
STOCKTON, CA 95203

LOCATION: 2526 W WASHINGTON ST
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, DRY SORBENT INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

CONDITIONS

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Authorities to Construct N-645-36-0, N-645-36-1, and N-645-36-2 shall be cancelled upon the implementation of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, the permittee shall surrender PM10 emission reduction credits in the following quantities: 1st quarter - 6,930 lb, 2nd quarter - 6,930 lb, 3rd quarter - 6,930 lb, and 4th quarter - 6,930 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services
N-645-36-3 : May 20 2016 2:20PM -- HARADERJ : Joint Inspection NOT Required

5. Prior to operating equipment under this Authority to Construct, the permittee shall surrender VOC emission reduction credits in the following quantities: 1st quarter - 2,175 lb, 2nd quarter - 2,175 lb, 3rd quarter - 2,175 lb, and 4th quarter - 2,175 lb. The emission reduction credit values listed in this condition already include the distance offset ratio of 1.5 to 1. [District Rule 2201] Federally Enforceable Through Title V Permit

6. ERC Certificate Number N-1007-5 (or one or more certificates split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. The permittee is authorized to utilize SOx ERC to satisfy the PM10 offset obligation specified in this permit. The use of SOx ERC to satisfy the PM10 offset obligation shall be conducted at an interpollutant offset ratio of 1:1. [District Rule 2201] Federally Enforceable Through Title V Permit

7. ERC Certificate Numbers S-3715-1 and S-4485-1 (or one or more certificates split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

8. 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 and 40 CFR 60.43b(f) and (g)] Federally Enforceable Through Title V Permit

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

11. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

12. 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] Federally Enforceable Through Title V Permit

13. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102] Federally Enforceable Through Title V Permit

14. The permittee shall conduct a performance tune-up of the boiler in accordance with the requirements of 40 CFR 63 Subpart JJJJJJ at least every 24 months. The permittee shall submit a signed statement in the Notification of Compliance Status indicating that each tune up was conducted. [40 CFR 63.11210] Federally Enforceable Through Title V Permit

15. The permittee shall calibrate and maintain in operation a selective catalytic reduction (SCR) system designed to reduce NOx emissions from the boiler exhaust stack to less than or equal to 0.040 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

16. The electrostatic precipitator shall be provided with continuous monitoring equipment showing the secondary power input, as specified in 40 CFR 63, Subpart JJJJJJ. The monitoring equipment shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201 and 40 CFR 63.11224] Federally Enforceable Through Title V Permit

17. The electrostatic precipitator shall be in operation whenever the boiler is operated on biomass. The electrostatic precipitator secondary power input, on a 12-hour block average, shall be maintained at or above the lowest 1-hour average secondary power input measured during the most recent performance test demonstrating compliance with the PM emission limitation, in accordance with Table 3 of 40 CFR 63, Subpart JJJJJJ. Transient voltage fluctuations due to arcs and sparks, or similar automatic functions of the electrostatic precipitator, shall not constitute deviations. The electrostatic precipitator shall be maintained in accordance with the manufacturer's recommendations, a copy of which shall be maintained on site. [District Rule 2201, 40 CFR 63.11221 and 40 CFR 64] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

18. The wet scrubber shall be provided with monitoring equipment that continuously monitors and records the effluent pH and flow rate of the scrubber liquid. [District Rule 2201] Federally Enforceable Through Title V Permit

19. The wet scrubber shall be in operation whenever the boiler is operated on biomass. The effluent pH and liquid flow rate, calculated on a rolling 30-day average basis, shall be maintained at or above the average pH and flow rate established during the most recent HCl source test. [District Rules 2201 and 4002] Federally Enforceable Through Title V Permit

20. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Startup is defined as the period of time beginning when the unit is heated to the operating temperature and pressure from a shutdown status or hot standby condition and ending only when the unit is firing on biomass or wood residue and is in compliance with the NOx, SOx, and CO emission limits for non-startup operation and with the minimum ESP secondary power input specified in this permit. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

22. Shutdown is defined as the period of time during which a unit is taken from operational to nonoperational status by allowing it to cool down from its operating temperature and pressure to an ambient temperature, or to a hot standby condition. Duration of shutdown shall not exceed 12 hours. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

23. Hot standby condition is defined as a condition in which all fuel feed has been curtailed and the boiler is secured at a temperature greater than the current ambient temperature. [District Rule 4352] Federally Enforceable Through Title V Permit

24. Flame stabilization is defined as any period in which supplemental use of a liquid or gaseous fuel is required in instances including control of one or more pollutants, or to alleviate or prevent unanticipated equipment outages or emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

25. This unit shall only be fired on biomass and wood residue, except that the unit may also be fired on natural gas during startup, shutdown, and flame stabilization periods. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

26. The total annual heat input to the unit from natural gas combustion shall not exceed 612,324 MMBtu in any one calendar year. [District Rules 4001 and 40 CFR 60.44b(d)] Federally Enforceable Through Title V Permit

27. Biomass is defined as any organic material originating from plants, not chemically treated and not derived from fossil fuels, including but not limited to products, by-products, and residues from agriculture, forestry, aquatic and related industries, such as agricultural, energy or feed crops and residues, orchard and vineyard prunings and removal, stone fruit pits, nut shells, cotton gin trash, corn stalks and stover, straw, seedhulls, sugarcane leavings and bagasse, aquatic plants and algae, cull logs, eucalyptus logs, poplars, willows, switchgrass, alfalfa, bark, lawn, yard and garden clippings, paper (unprinted), leaves, silvicultural residue, tree and brush pruning, sawdust, timber slash, mill scrap, wood and wood chips, and wood residue. Biomass does not include tires, material containing sewage sludge, or industrial, hazardous, radioactive, or municipal solid waste. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

28. Wood residue consists of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

29. Biomass and wood waste fuels shall not include pressure-treated wood and shall not contain compounds listed in Title 22, California Code of Regulations, 66261.24(a)(2)(A) in excess of the following concentrations by weight: 500 ppm antimony and/or antimony compounds, 500 ppm arsenic and/or arsenic compounds, 1,000 ppm asbestos, 10,000 ppm barium and/or barium compounds (excluding barite), 75 ppm beryllium and/or beryllium compounds, 100 ppm cadmium and/or cadmium compounds, 500 ppm chromium (VI) compounds, 2,500 ppm chromium and/or chromium (III) compounds, 8,000 ppm cobalt and/or cobalt compounds, 2,500 ppm copper and/or copper compounds, 18,000 ppm fluoride salts, 1,000 ppm lead and/or lead compounds, 20 ppm mercury and/or mercury compounds, 3,500 ppm molybdenum and/or molybdenum compounds, 2,000 ppm nickel and/or nickel compounds, 100 ppm selenium and/or selenium compounds, 500 ppm silver and/or silver compounds, 700 ppm thallium and/or thallium compounds, 2,400 ppm vanadium and/or vanadium compounds, and 5,000 ppm zinc and/or zinc compounds. [District Rule 4102]

30. The permittee shall be allowed a 24-month period to evaluate the operational variability and optimum control effectiveness of the proposed exhaust emission control system to meet the design emission rate of 0.040 lb-NOx/MMBtu. During the evaluation period, the permittee shall operate and maintain the boiler and the emission control system in such a manner as to minimize NOx emissions, and shall perform all required source testing and monitoring. The evaluation period shall begin upon the first day of the initial source test, and shall terminate after 24 months. [District Rule 2201] Federally Enforceable Through Title V Permit

31. During the 24-month evaluation period, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

32. During the 24-month evaluation period, the permittee shall submit annual status reports on the performance of the NOx emission control system. Each status report is due at the same time as the annual source test report. The status report shall, at a minimum, include actual operating time, calculated heat input to the boiler, actual NOx emissions as measured by the CEM system, daily and annual average actual NOx emission rates (in lb/MMBtu), and an analysis of system performance to date and expected performance for the next year. [District Rule 2201] Federally Enforceable Through Title V Permit

33. If NOx emissions continue to exceed, or are projected to exceed, 0.040 lbs/MMBtu on a block 24-hour average basis after the 24-month evaluation period, the permittee shall submit a final report containing all monitoring and source test data to the District within 90 days after the end of the evaluation period. The report shall include a detailed analysis of all factors that prevent achievement of the expected emission rate, as well as a detailed explanation of the steps taken to operate and maintain the boiler and the emission control system in such a manner as to minimize emissions. The report shall also propose an enforceable NOx emission limit, which shall not exceed 0.065 lb/MMBtu on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

34. Upon submittal of the report, the District shall re-evaluate BACT requirements for NOx from this class and category of source and establish an appropriate BACT emissions limit. Within 30 days of receipt of the District's determination, the permittee shall submit an Authority to Construct application to incorporate the revised emissions limit. In no case shall the NOx emission limitation be higher than 0.065 lbs/MMBtu on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

35. Following the 24-month evaluation period and prior to issuance of an Authority to Construct with a revised NOx emission limit, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

36. If NOx emissions do not exceed, and are not projected to exceed, the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis after the 24-month evaluation period, then the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis shall become an enforceable NOx emission limit. If the permittee fails to submit the required final report within 90 days after the end of the evaluation period, the permittee shall be considered to stipulate that an enforceable NOx emission limit of 0.040 lb/MMBtu on a block 24-hour average basis is achievable and will be made enforceable. [District Rule 2201] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

37. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.065 lb-NOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis as defined in District Rule 4352 (amended December 15, 2011). [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

38. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.74 lb-NOx/MMBtu. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

39. NOx emissions from this biomass-fired boiler shall not exceed 140.00 pounds in any one hour, as specified in District Rule 4301, Section 6.0. [District Rule 4301] Federally Enforceable Through Title V Permit

40. Except during periods of startup and shutdown, The emission rate from this biomass-fired boiler shall not exceed 0.09 lb-CO/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

41. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.67 lb-CO/MMBtu. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

42. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.054 lb-SOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rule 2201] Federally Enforceable Through Title V Permit

43. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.27 lb-SOx/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

44. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.0214 lb-PM10/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201] Federally Enforceable Through Title V Permit

45. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.078 lb-PM10/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

46. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.030 lb-PM/MMBtu [40 CFR 60.43b(h)(1) and 40 CFR 63.11201] Federally Enforceable Through Title V Permit

47. Except during periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.009 lb-VOC/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201] Federally Enforceable Through Title V Permit

48. During periods of startup and shutdown, the emission rate from this biomass-fired boiler shall not exceed 0.068 lb-VOC/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

49. The ammonia slip emission rate from this biomass-fired boiler shall not exceed 40 ppmvd @ 3% O2. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 4102]

50. HCl emissions from this biomass-fired boiler shall not exceed 19,980 pounds in any rolling 365 consecutive day period. HCl emissions shall be calculated daily for comparison to this annual limit using the daily boiler heat input determined pursuant to 40 CFR Part 75, Appendix F, Equation F-15 and the emission factor calculated in the most recent HCl source test. If HCl emissions from the biomass boiler, including emissions from startup, shutdown or malfunction periods are determined to have exceeded 19,999 pounds in any rolling 365-day period, the owner/operator shall submit an Authority to Construct application to comply with 40 CFR 63 Subpart DDDDDD requirements within 30 days of the exceedance. [District Rules 2201 and 4002] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

51. Emissions from this biomass-fired boiler shall not exceed any of the following limits: 1st Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 2nd Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 3rd Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 4th Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 26,824 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC. Compliance with NOx, SOx, and CO limits shall be determined from CEM data. Compliance with PM10 and VOC limits shall be calculated using emission factors (the most recent source test results for non-startup/shutdown operation, or the startup/shutdown emission factors at all other times), heat input to the boiler, and operating time. [District Rule 2201] Federally Enforceable Through Title V Permit

52. 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 shall be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

53. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

54. 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 1081 and 2201] Federally Enforceable Through Title V Permit

55. This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits within 60 days of achieving the maximum steam production rate, but no more than 180 days after initial startup, and at least once every 12 months thereafter. The PM source test required by condition 55 may be conducted in lieu of PM10 testing required by this condition, provided all PM is assumed to be PM10 as specified in condition 64. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

56. This unit shall be tested for compliance with the PM emission limit within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 36 months thereafter. [40 CFR 60.8(a), 40 CFR 60.43b(d), and 40 CFR 63.11220(a)] Federally Enforceable Through Title V Permit

57. This unit shall be tested to determine the HCl emission factor within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. The permittee shall measure and record the effluent pH and liquid flow rate in the wet scrubber every 15 minutes during the source test. [District Rule 2201] Federally Enforceable Through Title V Permit

58. Permittee shall test fuel to determine the higher heating value at least once every 12 months. [District Rules 1081 and 2201, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

59. Permittee shall test fuel for contaminants within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter, or whenever requested by the District. The District shall be notified at least 15 days prior to scheduled sample collection. [District Rules 2201 and 4102, and 40 CFR 60.8(a)] Federally Enforceable Through Title V Permit

60. Testing of the fuel for contaminants shall be conducted on a representative sample collected upstream of and as close as practicable to the fuel metering bins. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

61. Fuel shall be tested for contaminants in accordance with the wet extraction test procedure detailed in Title 22 California Code of Regulations, Division 4.5, Chapter 11, Appendix II. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

62. NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or ARB Method 100 and EPA Method 19. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

63. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

64. PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

65. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081] Federally Enforceable Through Title V Permit

66. PM emissions required to be source tested under condition 55 shall be determined using EPA Methods 5 or 17 (filterable (front half) PM only), and 19. [40 CFR 60.43b(d)(2) and 40 CFR 63.11212] Federally Enforceable Through Title V Permit

67. Stack gas oxygen shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

68. SOx emissions for source test purposes shall be determined using EPA Method 6 or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

69. VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rules 1081 and 4352] Federally Enforceable Through Title V Permit

70. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

71. HCl emissions for source test purposes shall be determined using EPA Methods 26 or 26A, and 19. [District Rule 2201] Federally Enforceable Through Title V Permit

72. Testing for fuel higher heating value shall be conducted using ASTM Method D5865-01a or District-approved equivalent method. [District Rules 1081 and 4352, and 40 CFR 75 Appendix F] Federally Enforceable Through Title V Permit

73. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, SOx, and CO2. Additionally, the exhaust stack shall be equipped with a flow monitor. The CEM shall meet the requirements of 40 CFR parts 60 (for CO) and 75 (for NOx, SOx, and CO2), except as specified in 40 CFR 60, Subpart Db, and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. The CEM shall be used to demonstrate compliance with the Rule 2201 emission limits. [District Rules 1080 and 2201] Federally Enforceable Through Title V Permit

74. Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) in accordance with 40 CFR 60.48b, and 40 CFR 60 Appendices B and F. The sampling and analyzing cycle shall be completed every successive 10 second period, and the recording cycle shall be completed every successive 6 minute period. The COMS shall be used to demonstrate compliance with the opacity requirements of 40 CFR 43b(f) and (g). [District Rules 1080 and 2201, and 40 CFR 60.48b(a)] Federally Enforceable Through Title V Permit

75. Permittee 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] Federally Enforceable Through Title V Permit

76. 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] Federally Enforceable Through Title V Permit

77. 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 either an O2 or CO2 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] Federally Enforceable Through Title V Permit

78. 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] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

79. Permittee shall perform a relative accuracy test audit (RATA), as specified by 40 CFR Part 75, Appendix B, 2.3.1 for the NOx, SOx, and O2 or CO2 CEM,, at least once every two successive QA operating quarters (as defined in 40 CFR 72.2) unless the monitor satisfies the requirements for reduced RATA frequencies in Section 2.3.1.2. Permittee shall perform a RATA, as specified by 40 CFR Part 60, Appendix F for the CO CEM, at least once every four calendar quarters. Permittee shall perform a cylinder gas audit (CGA) or relative accuracy audit (RAA), as specified by 40 CFR Part 60, Appendix F for the CO CEM in three of four calendar quarters, but no more than three quarters in succession. The District must be notified at least 30 days prior to any RATA, and a test plan shall be submitted for approval at least 15 days prior to testing. The results of each RATA shall be submitted to the District within 60 days thereafter. [District Rule 1080] Federally Enforceable Through Title V Permit

80. 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 75, Appendix B for the NOx, SOx, and O2 or CO2 CEM, and in 40 CFR Part 60, Appendix F for the CO CEM. [District Rule 1080] Federally Enforceable Through Title V Permit

81. 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] Federally Enforceable Through Title V Permit

82. When using measurements taken by the CO2 analyzer for emission compliance determinations, the following formula shall be used to convert the emission concentration referenced at 12 percent CO2 to an emission concentration referenced at 3 percent O2: E at 3%O2 = E at 12%CO2 x (CO2 F-Factor ÷ O2 F-Factor) x (100 ÷ 12) x (20.9 - 3) ÷ 20.9. Where, the CO2 F-Factor is in terms of scf CO2/MMBtu and the O2 F-Factor is in terms of dscf/MMBtu at 0% O2. Permittee may choose to use the default CO2 and O2 F-Factors for wood listed in 40 CFR Method 19, or may choose to use site-specific F-Factors. If using site specific F-Factors, permittee shall re-determine the site-specific F-Factors annually using at least 9 fuel samples. The site-specific F-Factors shall be determined in accordance with EPA Method 19. [District Rules 1080 and 2080, and 40 CFR 60] Federally Enforceable Through Title V Permit

83. Permittee shall keep records of site-specific F-Factor determinations, including the date of each determination, the corresponding CO2 F-Factor, and the corresponding O2 F-Factor. [District Rules 1080 and 2080, and 40 CFR 60] Federally Enforceable Through Title V Permit

84. Permittee shall maintain records of the date and duration of start-up and shutdown periods. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

85. Permittee shall record the heat input to the unit from each fuel combusted on a daily basis. Permittee shall maintain records of the annual capacity factor for each fuel combusted on a 12-month rolling average basis, and shall update the annual capacity factor for each fuel at the end of each calendar month. [District Rules 1070 and 4001, and 40 CFR 60.49b(d)(1)] Federally Enforceable Through Title V Permit

86. Permittee shall retain and maintain on site all data from the continuous opacity monitoring system. [District Rules 1070 and 4001, and 40 CFR 60.39b(f)] Federally Enforceable Through Title V Permit

87. Permittee shall maintain, on at least a monthly basis, an operating log that includes the type and quantity of fuel used, and the higher heating value of each fuel, as determined by Section 6.3 of District Rule 4352 (12/15/11), or as certified by a third party fuel supplier. [District Rules 1070 and 4352] Federally Enforceable Through Title V Permit

88. Permittee shall maintain records of emissions from this boiler on a calendar quarter basis. Records of quarterly emissions shall be updated at least once each calendar month in which the boiler operates. [District Rule 2201] Federally Enforceable Through Title V Permit

89. Permittee shall maintain records of HCl emissions from this boiler on a rolling consecutive day basis. Records of HCl emissions shall be updated at least once each calendar day in which the boiler operates. [District Rules 2201, 4002, and 4102] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

90. The permittee shall maintain records of the criteria used to establish that the unit qualifies as a small power production facility under section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)) and that the waste material the unit is proposed to burn is homogeneous (not including refuse-derived fuel). [40 CFR 60.2175(w)] Federally Enforceable Through Title V Permit

91. Permittee shall keep the results of the most recent source test, including the measure HCl emission rate and the applicable scrubber operating parameters, onsite. [District Rule 2201] Federally Enforceable Through Title V Permit

92. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 2201 and 4352] Federally Enforceable Through Title V Permit

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Appendix B
Authorities to Construct from District Project N-1101175

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-8-5 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
MODIFICATION TO CONVERT SILO TO TRONA. POST-PROJECT EQUIPMENT DESCRIPTION IS: TRONA RECEIVING SILO #1 CONTROLLED BY A FABRIC FILTER BAGHOUSE

CONDITIONS

1. Trona shall be received through direct coupled pneumatic unloading truck. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The pneumatic transfer components and connections shall be totally air tight. [District NSR Rule] Federally Enforceable Through Title V Permit
3. The storage silos shall be totally air tight and vented only through a fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
4. The fabric filters shall have a maximum effective air to cloth ratio of 4.5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
5. There shall be no visible emissions from the fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
6. The fabric filter baghouse shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. The differential pressure across each compartment shall be maintained between 1" and 8" water column. [District NSR Rule and 2520, 9.3.2] Federally Enforceable Through Title V Permit
7. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services

8. Fabric collection system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

9. Fabric collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

10. Records of fabric collector system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual Performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

11. Visible emissions from the the trona receiving silo shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

12. The differential pressure across each compartment of the fabric filter baghouse shall be checked and the results recorded annually. If the differential pressure across each compartment of the fabric filters is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.] Federally Enforceable Through Title V Permit

13. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

14. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

15. PM10 emissions from the trona receiving and storage operation shall not exceed 0.00039 pounds per ton of trona received. [District Rule 2201]

16. The quantity of trona received shall not exceed 365 tons in any one day and 27,375 tons in any rolling 12-consecutive-month period. [District Rule 2201]

17. Permittee shall maintain daily records of the quantity of trona received, in tons, and shall update the rolling 12-consecutive-month total of trona received at least once each calendar month. [District Rule 2201]

18. Records shall be retained on-site for a period of at least five years and made available for District inspection upon request. [District Rule 2201]

19. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

20. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

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

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-9-5 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
MODIFICATION TO REPLACE LIMESTONE USE WITH TRONA. POST-PROJECT EQUIPMENT DESCRIPTION IS: TRONA RECEIVING SILO #2 CONTROLLED BY A FABRIC FILTER BAGHOUSE

CONDITIONS

1. Trona shall be received through direct coupled pneumatic unloading truck. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The pneumatic transfer components and connections shall be totally air tight. [District NSR Rule] Federally Enforceable Through Title V Permit
3. The storage silos shall be totally air tight and vented only through a fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
4. The fabric filters shall have a maximum effective air to cloth ratio of 4.5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
5. There shall be no visible emissions from the fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
6. The fabric filter baghouse shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. The differential pressure across each compartment shall be maintained between 1" and 8" water column. [District NSR Rule and 2520, 9.3.2] Federally Enforceable Through Title V Permit
7. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services
N-645-9-5 : Jun 9 2011 11:53AM -- DEMARISF : Joint Inspection NOT Required

8. Fabric collection system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

9. Fabric collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

10. Records of fabric collector system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual Performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

11. Visible emissions from the the trona receiving silo shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

12. The differential pressure across each compartment of the fabric filter baghouse shall be checked and the results recorded annually. If the differential pressure across each compartment of the fabric filters is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.] Federally Enforceable Through Title V Permit

13. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

14. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

15. PM10 emissions from the trona receiving and storage operation shall not exceed 0.00039 pounds per ton of trona received. [District Rule 2201]

16. The quantity of trona received shall not exceed 365 tons in any one day and 27,375 tons in any rolling 12-consecutive-month period. [District Rule 2201]

17. Permittee shall maintain daily records of the quantity of trona received, in tons, and shall update the rolling 12-consecutive-month total of trona received at least once each calendar month. [District Rule 2201]

18. Records shall be retained on-site for a period of at least five years and made available for District inspection upon request. [District Rule 2201]

19. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

20. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

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

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-34-4 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
MODIFICATION TO REDUCE VOC LIMIT. POST-PROJECT EQUIPMENT DESCRIPTION IS: 43,000 GALLON PER MINUTE COOLING TOWER

CONDITIONS

1. VOC emissions from the addition of VOC-containing chemicals to the cooling tower water shall not exceed 0.8 pounds in any one day. [District Rule 2201]
2. Permittee shall maintain a log recording the amount of VOC containing material added each day. [District NSR Rule] Federally Enforceable Through Title V Permit
3. A list of materials added to the cooling tower and their VOC content shall be kept and made available for District inspection upon request. [District NSR Rule] Federally Enforceable Through Title V Permit
4. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]
5. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit
6. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services
N-645-34-4 : Jun 8 2011 11:53AM – DEMARISF : Joint Inspection NOT Required

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-36-0 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, TRONA INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

CONDITIONS

1. Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantities of emissions: 1st quarter - 6,929 lb, 2nd quarter - 6,930 lb, 3rd quarter - 6,930 lb, and fourth quarter -6,930 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
2. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantities of emissions: 1st quarter - 1,450 lb, 2nd quarter - 1,450 lb, 3rd quarter - 1,450 lb, and fourth quarter - 1,450 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
3. ERC Certificate Numbers S-2937-4, S-3199-4, S-2971-4, N-717-5, N-718-5, N-931-5, and S-3413-5 (or one or more certificates split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services

N-645-36-0 : Jun 9 2011 11:53AM -- DEMARISF : Joint Inspection NOT Required

4. ERC Certificate Numbers S-2775-1, S-3373-1, S-3132-1, S-3051-1, S-3504-1, S-3505-1, and S-3503-1 (or one or more certificates split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201]

5. The permittee is authorized to utilize SOx ERC to satisfy the offset obligation specified in Condition 1. The use of SOx ERC to satisfy the PM10 offset obligation shall be conducted at an interpollutant offset ratio of 1:1. [District Rule 2201]

6. Prior to initial startup of the equipment authorized by this ATC, permittee shall permanently remove from service, and surrender the operating permit for, units N-645-2, '-3, '-4, '-7, '-10, '-11, '-14, '-16, '-20, '-23, '-24, '-31, and '-35. [District Rule 2201]

7. Permittee shall minimize the emissions from the boiler to the maximum extent possible during the commissioning period. Conditions 7 through 15 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions 16 through 95 shall apply after the commissioning period has ended. [District Rule 2201]

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

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

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

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, each of the pollution control devices (trona injection system, multiclone, electrostatic precipitator, oxidation catalyst, selective catalytic reduction system) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the combustor, the installation and operation of each of the pollution control devices, the installation, calibration, and testing of the continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the pollution control devices. [District Rule 2201]

13. Emission rates from the boiler, during the commissioning period, shall not exceed any of the following emission rates: 6,652.8 lb-NOx/day; 2,138.4 lb-SOx/day; 1,188.0 lb-PM10/day; 6,019.2 lb-CO/day; and 617.8 lb-VOC/day. During the commissioning period, the permittee shall demonstrate compliance with the NOx, SOx, and CO emission limits through the use of properly operated and maintained continuous emissions monitors (CEM) and recorders. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). An exceedance of the NOx, SOx, and CO emission limits, as measured by the continuous emission monitors, shall be a violation of this permit condition. During the commissioning period, the permittee shall demonstrate compliance with the PM10 and VOC emission limits by calculating emissions, using the heat input to the boiler, the operating time, and the emission factors specified in this condition, during each day in which the boiler is operated. PM10 emissions shall be calculated using an emission factor of 0.0214 lb/MMBtu when the ESP secondary power input equals or exceeds the minimum specified in condition 25, and an emission factor of 0.15 lb/MMBtu at all other times. VOC emissions shall be calculated using an emission factor of 0.009 lb/MMBtu when the CO CEM indicates the CO emission rate is below 0.09 lb/MMBtu, and an emission factor of 0.078 lb/MMBtu at all other times. An exceedance of the PM10 and VOC emission limits, as calculated, shall be a violation of this permit condition. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

14. The continuous emissions monitors (CEM) specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEM shall be adjusted as necessary to accurately measure the resulting range of emissions concentrations. [District Rule 2201]

15. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall be counted toward the quarterly emission limits specified in condition 56. NOx, SOx, and CO total mass emissions shall be determined from CEM data, while PM10 and VOC total mass emissions shall be calculated using the heat input to the boiler, the operating time, and the emission factors specified in this condition, during each day in which the boiler is operated. PM10 emissions shall be calculated using an emission factor of 0.0214 lb/MMBtu when the ESP secondary power input equals or exceeds the minimum specified in condition 25, and an emission factor of 0.15 lb/MMBtu at all other times. VOC emissions shall be calculated using an emission factor of 0.009 lb/MMBtu when the CO CEM indicates the CO emission rate is below 0.09 lb/MMBtu, and an emission factor of 0.078 lb/MMBtu at all other times. [District Rule 2201]

16. 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 and 40 CFR 60.43b(f) and (g)]

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

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

19. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202]

20. 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]

21. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

22. The permittee shall conduct a performance tune-up of the boiler in accordance with the requirements of 40 CFR 63 Subpart JJJJJJ within 180 days of initial startup, and at least every 24 months thereafter. The permittee shall submit a signed statement in the Notification of Compliance Status indicating that each tune up was conducted. [40 CFR 63.11210]

23. The permittee shall calibrate and maintain in operation a selective catalytic reduction (SCR) system designed to reduce NOx emissions from the boiler exhaust stack to less than or equal to 0.040 lb/MMBtu. [District Rule 2201]

24. The electrostatic precipitator shall be provided with continuous monitoring equipment showing the secondary power input, as specified in 40 CFR 63, Subpart JJJJJJ. The monitoring equipment shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201 and 40 CFR 63.11224]

25. The electrostatic precipitator shall be in operation whenever the boiler is operated on biomass. The electrostatic precipitator secondary power input, on a 12-hour block average, shall be maintained at or above the lowest 1-hour average secondary power input measured during the most recent performance test demonstrating compliance with the PM emission limitation, in accordance with Table 3 of 40 CFR 63, Subpart JJJJJJ. Transient voltage fluctuations due to arcs and sparks, or similar automatic functions of the electrostatic precipitator, shall not constitute deviations. The electrostatic precipitator shall be maintained in accordance with the manufacturer's recommendations, a copy of which shall be maintained on site. [District Rule 2201, 40 CFR 63.11221 and 40 CFR 64]

26. The wet scrubber shall be provided with monitoring equipment that continuously monitors and records the effluent pH and flow rate of the scrubber liquid. [District Rule 2201]

27. The wet scrubber shall be in operation whenever the boiler is operated on biomass. The effluent pH and liquid flow rate, calculated on a 24-hour block average basis, shall be maintained at or above the average pH and flow rate established during the most recent HCl source test. [District Rule 2201]

28. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201]

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29. Startup is defined as the period of time beginning with initial boiler firing and ending only when the unit is firing on biomass or wood residue and is in compliance with the NOx, SOx, and CO emission limits for non-startup and shutdown operation, and with the minimum ESP secondary power input requirement specified in condition 25. Shutdown is defined as the period of time beginning with the initiation of the boiler shutdown sequence and ending with the cessation of combustion in the boiler. [District Rule 2201]

30. This unit shall only be fired on biomass and wood residue, except that the unit may also be fired on natural gas during startup, shutdown, and flame stabilization periods. [District Rules 2201 and 4102]

31. The total annual heat input to the unit from natural gas combustion shall not exceed 612,324 MMBtu in any one calendar year. [District Rules 4001 and 40 CFR 60.44b(d)]

32. Biomass is defined as any organic material originating from plants, not chemically treated and not derived from fossil fuels, including but not limited to products, by-products, and residues from agriculture, forestry, aquatic and related industries, such as agricultural, energy or feed crops and residues, orchard and vineyard prunings and removal, stone fruit pits, nut shells, cotton gin trash, corn stalks and stover, straw, seedhulls, sugarcane leavings and bagasse, aquatic plants and algae, cull logs, eucalyptus logs, poplars, willows, switchgrass, alfalfa, bark, lawn, yard and garden clippings, paper (unprinted), leaves, silvicultural residue, tree and brush pruning, sawdust, timber slash, mill scrap, wood and wood chips, and wood residue. Biomass does not include tires, material containing sewage sludge, or industrial, hazardous, radioactive, or municipal solid waste. [District Rules 2201 and 4102]

33. Wood residue consists of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. [District Rules 2201 and 4102]

34. Biomass and wood waste fuels shall not include pressure-treated wood and shall not contain compounds listed in Title 22, California Code of Regulations, 66261.24(a)(2)(A) in excess of the following concentrations by weight: 500 ppm antimony and/or antimony compounds, 500 ppm arsenic and/or arsenic compounds, 1,000 ppm asbestos, 10,000 ppm barium and/or barium compounds (excluding barite), 75 ppm beryllium and/or beryllium compounds, 100 ppm cadmium and/or cadmium compounds, 500 ppm chromium (VI) compounds, 2,500 ppm chromium and/or chromium (III) compounds, 8,000 ppm cobalt and/or cobalt compounds, 2,500 ppm copper and/or copper compounds, 18,000 ppm fluoride salts, 1,000 ppm lead and/or lead compounds, 20 ppm mercury and/or mercury compounds, 3,500 ppm molybdenum and/or molybdenum compounds, 2,000 ppm nickel and/or nickel compounds, 100 ppm selenium and/or selenium compounds, 500 ppm silver and/or silver compounds, 700 ppm thallium and/or thallium compounds, 2,400 ppm vanadium and/or vanadium compounds, and 5,000 ppm zinc and/or zinc compounds. [District Rule 4102]

35. The permittee shall be allowed a 24-month period to evaluate the operational variability and optimum control effectiveness of the proposed exhaust emission control system to meet the design emission rate of 0.040 lb-NOx/MMBtu. During the evaluation period, the permittee shall operate and maintain the boiler and the emission control system in such a manner as to minimize NOx emissions, and shall perform all required source testing and monitoring. The evaluation period shall begin upon the first day of the initial source test, and shall terminate after 24 months. [District Rule 2201]

36. During the 24-month evaluation period, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]

37. During the 24-month evaluation period, the permittee shall submit annual status reports on the performance of the NOx emission control system. Each status report is due at the same time as the annual source test report. The status report shall, at a minimum, include actual operating time, calculated heat input to the boiler, actual NOx emissions as measured by the CEM system, daily and annual average actual NOx emission rates (in lb/MMBtu), and an analysis of system performance to date and expected performance for the next year. [District Rule 2201]

38. If NOx emissions continue to exceed, or are projected to exceed, 0.040 lbs/MMBtu on a block 24-hour average basis after the 24-month evaluation period, the permittee shall submit a final report containing all monitoring and source test data to the District within 90 days after the end of the evaluation period. The report shall include a detailed analysis of all factors that prevent achievement of the expected emission rate, as well as a detailed explanation of the steps taken to operate and maintain the boiler and the emission control system in such a manner as to minimize emissions. The report shall also propose an enforceable NOx emission limit, which shall not exceed 0.065 lb/MMBtu on a block 24-hour average basis. [District Rule 2201]

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39. Upon submittal of the report, the District shall re-evaluate BACT requirements for NOx from this class and category of source and establish an appropriate BACT emissions limit. Within 30 days of receipt of the District's determination, the permittee shall submit an Authority to Construct application to incorporate the revised emissions limit. In no case shall the NOx emission limitation be higher than 0.065 lbs/MMBtu on a block 24-hour average basis. [District Rule 2201]
40. Following the 24-month evaluation period and prior to issuance of an Authority to Construct with a revised NOx emission limit, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]
41. If NOx emissions do not exceed, and are not projected to exceed, the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis after the 24-month evaluation period, then the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis shall become an enforceable NOx emission limit. If the permittee fails to submit the required final report within 90 days after the end of the evaluation period, the permittee shall be considered to stipulate that an enforceable NOx emission limit of 0.040 lb/MMBtu on a block 24-hour average basis is achievable and will be made enforceable. [District Rule 2201]
42. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.065 lb-NOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis as defined in District Rule 4352 (amended May 18, 2006). [District Rules 2201 and 4352]
43. During periods of startup and shutdown emission rate from this biomass-fired boiler shall not exceed 0.74 lb-NOx/MMBtu. [District Rules 2201 and 4352]
44. NOx emissions from this biomass-fired boiler shall not exceed 140.00 pounds in any one hour, as specified in District Rule 4301, Section 6.0. [District Rule 4301]
45. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.09 lb-CO/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rules 2201 and 4352]
46. During periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.67 lb-CO/MMBtu. [District Rules 2201 and 4352]
47. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.054 lb-SOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis. [District Rule 2201]
48. During periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.27 lb-SOx/MMBtu. [District Rule 2201]
49. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.0214 lb-PM10/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201]
50. During periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.078 lb-PM10/MMBtu. [District Rule 2201]
51. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.030 lb-PM/MMBtu [40 CFR 60.43b(h)(1) and 40 CFR 63.11201]
52. Except during periods of startup and shutdown, emission rates from this biomass-fired boiler shall not exceed 0.009 lb-VOC/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 2201]
53. During periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.068 lb-VOC/MMBtu. [District Rule 2201]
54. Ammonia slip emission rate from this biomass-fired boiler shall not exceed 40 ppmvd @ 3% O2. Initial and annual compliance with this limit shall be demonstrated by source testing. [District Rule 4102]

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55. HCl emissions from this biomass-fired boiler shall not exceed 19,980 pounds in any rolling 12-consecutive-month period. HCl emissions shall be calculated for comparison to this annual limit using the boiler heat input and the emission factor calculated in the most recent HCl source test. [District Rule 2201]

56. Emissions from this biomass-fired boiler shall not exceed any of the following limits: 1st Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 29,133 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 2nd Quarter: 53,837 lb-NOx, 34,785 lb-SOx, 29,134 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 3rd Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 29,134 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC; 4th Quarter: 53,838 lb-NOx, 34,785 lb-SOx, 29,134 lb-PM10, 123,959 lb-CO, and 12,400 lb-VOC. Compliance with NOx, SOx, and CO limits shall be determined from CEM data. Compliance with PM10 and VOC limits shall be calculated using emission factors (the most recent source test results for non-startup/shutdown operation, or the startup/shutdown emission factors at all other times), heat input to the boiler, and operating time. [District Rule 2201]

57. 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 shall be submitted for approval at least 15 days prior to testing. [District Rule 1081]

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

59. 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 1081 and 2201]

60. This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. The PM source test required by condition 61 may be conducted in lieu of PM10 testing required by this condition, provided all PM is assumed to be PM10 as specified in condition 70. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)]

61. This unit shall be tested for compliance with the PM emission limit within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 36 months thereafter. [40 CFR 60.8(a), 40 CFR 60.43b(d), and 40 CFR 63.11220(a)]

62. This unit shall be tested to determine the HCl emission factor within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. The permittee shall measure and record the effluent pH and liquid flow rate in the wet scrubber every 15 minutes during the source test. [District Rule 2201]

63. Permittee shall test fuel to determine the higher heating value within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter. [District Rules 1081 and 2201, and 40 CFR 60.8(a)]

64. Permittee shall test fuel for contaminants within 60 days of achieving the maximum steam production rate at which the unit will be operated, but not more than 180 days after initial startup, and at least once every 12 months thereafter, or whenever requested by the District. The District shall be notified at least 15 days prior to scheduled sample collection. [District Rules 2201 and 4102, and 40 CFR 60.8(a)]

65. Testing of the fuel for contaminants shall be conducted on a representative sample collected upstream of and as close as practicable to the fuel metering bins. [District Rules 2201 and 4102]

66. Fuel shall be tested for contaminants in accordance with the wet extraction test procedure detailed in Title 22 California Code of Regulations, Division 4.5, Chapter 11, Appendix II. [District Rules 2201 and 4102]

67. NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or ARB Method 100 and EPA Method 19. [District Rules 1081 and 4352]

68. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 1081 and 4352]

69. PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352]

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70. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081]

71. PM emissions required to be source tested under condition 61 shall be determined using EPA Methods 5 or 17 (filterable (front half) PM only), and 19. [40 CFR 60.43b(d)(2) and 40 CFR 63.11212]

72. Stack gas oxygen shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 1081 and 4352]

73. SOx emissions for source test purposes shall be determined using EPA Method 6 or ARB Method 100. [District Rules 1081 and 4352]

74. VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rules 1081 and 4352]

75. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rules 1081 and 2201]

76. HCl emissions for source test purposes shall be determined using EPA Methods 26 or 26A, and 19. [District Rule 2201]

77. Testing for fuel higher heating value shall be conducted using ASTM Method D5865-01a or District-approved equivalent method. [District Rules 1081 and 4352, and 40 CFR 75 Appendix F]

78. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, SOx, and O2. The CEM shall meet the requirements of 40 CFR parts 60 (for CO) and 75 (for NOx, SOx, and O2), except as specified in 40 CFR 60, Subpart Db, and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. The CEM shall be used to demonstrate compliance with the Rule 2201 emission limits. [District Rules 1080 and 2201]

79. Permittee shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) in accordance with 40 CFR 60.48b, and 40 CFR 60 Appendices B and F. The sampling and analyzing cycle shall be completed every successive 10 second period, and the recording cycle shall be completed every successive 6 minute period. The COMS shall be used to demonstrate compliance with the opacity requirements of 40 CFR 43b(f) and (g). [District Rules 1080 and 2201, and 40 CFR 60.48b(a)]

80. Permittee 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]

81. 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]

82. 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]

83. 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]

CONDITIONS CONTINUE ON NEXT PAGE

84. Permittee shall perform a relative accuracy test audit (RATA), as specified by 40 CFR Part 75, Appendix B, 2.3.1 for the NOx, SOx, and O2 CEM,, at least once every two successive QA operating quarters (as defined in 40 CFR 72.2) unless the monitor satisfies the requirements for reduced RATA frequencies in Section 2.3.1.2. Permittee shall perform a RATA, as specified by 40 CFR Part 60, Appendix F for the CO CEM, at least once every four calendar quarters. Permittee shall perform a cylinder gas audit (CGA) or relative accuracy audit (RAA), as specified by 40 CFR Part 60, Appendix F for the CO CEM in three of four calendar quarters, but no more than three quarters in succession. The District must be notified at least 30 days prior to any RATA, and a test plan shall be submitted for approval at least 15 days prior to testing. The results of each RATA shall be submitted to the District within 60 days thereafter. [District Rule 1080]

85. 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 75, Appendix B for the NOx, SOx, and O2 CEM, and in 40 CFR Part 60, Appendix F for the CO CEM. [District Rule 1080]

86. 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]

87. Permittee shall maintain records of the date and duration of start-up and shutdown periods. [District Rules 2201 and 4352]

88. Permittee shall record the heat input to the unit from each fuel combusted on a daily basis. Permittee shall maintain records of the annual capacity factor for each fuel combusted on a 12-month rolling average basis, and shall update the annual capacity factor for each fuel at the end of each calendar month. [District Rules 1070 and 4001, and 40 CFR 60.49b(d)(1)]

89. Permittee shall retain and maintain on site all data from the continuous opacity monitoring system. [District Rules 1070 and 4001, and 40 CFR 60.39b(f)]

90. Permittee shall maintain records of solid fuel higher heating value and fuel contaminant testing results. [District Rules 1070 and 4352]

91. Permittee shall maintain records of emissions from this boiler on a calendar quarter basis. Records of quarterly emissions shall be updated at least once each calendar month in which the boiler operates. [District Rule 2201]

92. Permittee shall maintain records of HCl emissions from this boiler on a rolling 12-consecutive-month basis. Records of HCl emissions shall be updated at least once each calendar month in which the boiler operates. [District Rules 2201, 4002, and 4102]

93. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 2201 and 4352]

94. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

95. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-37-0 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
BIOMASS RECEIVING OPERATION WITH THREE TRUCK UNLOADING HOPPERS, A DISC SCREEN AND HOGGER, AND ASSOCIATED CONVEYORS, AND BIOMASS STORAGE OPERATION WITH UP TO 5.5 ACRES OF BIOMASS STORAGE PILES

CONDITIONS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202]
4. All stockpiled biomass shall be covered, or maintained adequately moist, to prevent visible emissions in excess of 20% opacity as determined using EPA Method 9. Permittee shall use water sprays or other dust suppression techniques as necessary to ensure compliance with this opacity limit. [District Rule 2201]
5. Visible emissions from the disc screen, fuel hogger, and all conveyor transfer points shall not exceed 20% opacity as determined using EPA Method 9. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services
N-645-37-0 Jun 9 2011 11:53AM – DEMARISF , Joint Inspection NOT Required

6. Permittee shall monitor the disc screen, fuel hogger, and all conveyor transfer points for visible emissions, as determined using EPA Method 22 on a daily basis. Daily monitoring shall take place at an appropriate time each day depending on plant start time and sunrise, but shall in any event be conducted before 12:00 PM. If visible emissions are detected, permittee shall take corrective action and eliminate visible emissions within 1 hour after detection. If visible emissions cannot be eliminated within 1 hour after detection, a visible emissions test using EPA Method 9 shall be conducted while the visible emissions are ongoing to determine if the visible emissions exceed the limits specified in this permit. Visible emissions less than 20% opacity as determined using EPA Method 9 shall not constitute a violation of this condition. [District Rule 2201]

7. 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]

8. PM10 emissions from the biomass fuel receiving operation shall not exceed 0.000301 lb/ton on a daily average basis and 0.000527 lb/ton on an annual average basis. [District Rule 2201]

9. Biomass fuel received by the receiving and storage operation shall not exceed 2,732 tons in any one day and 470,080 tons in any calendar year. [District Rule 2201]

10. Emissions from the biomass fuel storage piles shall not exceed 0.24 lb-PM10 per acre of fuel storage piles per day. [District Rule 2201]

11. Permittee shall maintain records of the quantity of biomass fuel received each day, in tons. [District Rule 2201]

12. Records shall be retained on-site for a period of at least five years and made available for District inspection upon request. [District Rule 2201]

13. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

14. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

15. 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]

16. 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]

17. When handling bulk materials outside an enclosed structure or building, water or chemical/organic stabilizers/suppressants shall be applied as required to limit Visible Dust Emissions to a maximum of 20% opacity. When necessary to achieve this opacity limitation, wind barriers with less than 50% porosity shall also be used. [District Rules 2201, 8011, and 8031]

18. When storing bulk materials outside an enclosed structure or building, water or chemical/organic stabilizers/suppressants shall be applied as required to limit Visible Dust Emissions to a maximum of 20% opacity. When necessary to achieve this opacity limitation, all bulk material piles shall also be either maintained with a stabilized surface as defined in Section 3.58 of District Rule 8011, or shall be protected with suitable covers or barriers as prescribed in Table 8031-1, Section B, of District Rule 8031. [District Rules 2201, 8011, and 8031]

19. When transporting bulk materials outside an enclosed structure or building, all bulk material transport vehicles shall limit Visible Dust Emissions to 20% opacity by either limiting vehicular speed, maintaining sufficient freeboard on the load, applying water to the top of the load, or covering the load with a tarp or other suitable cover. [District Rules 8011 and 8031]

20. All outdoor chutes and conveyors shall be controlled by any of the following options: 1) full enclosure, 2) operation with water spray equipment that sufficiently wets materials to limit VDE to 20% opacity, or 3) the concentration of particles having an aerodynamic diameter of 10 microns or less in the conveyed material shall be sufficiently small to limit VDE to 20% opacity. [District Rules 2201, 8011, and 8031]

CONDITIONS CONTINUE ON NEXT PAGE

21. 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]

22. 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 8041]

23. 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]

24. 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]

25. 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]

26. 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]

27. 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]

28. 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]

29. Upon implementation of this Authority to Construct, ATC N-645-39-0 shall be cancelled. [District Rule 2201]

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-38-0 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
BIOMASS FUEL HANDLING OPERATION WITH BIOMASS METERING BINS, RECLAIM CONVEYORS, AND OTHER ASSOCIATED CONVEYORS

CONDITIONS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202]
4. Visible emissions from all conveyor transfer points shall not exceed 20% opacity as determined using EPA Method 9. [District Rule 2201]
5. Permittee shall not cause or allow visible emissions from any conveyor transfer point, as determined using EPA Method 22 on a daily basis. Daily inspections shall take place at an appropriate time each day depending on plant start time and sunrise. If visible emissions cannot be corrected within 1 hour after detection, a visible emissions test using EPA Method 9 shall be conducted while the visible emissions are ongoing to determine if the visible emissions exceed the limit in condition 4. Visible emissions less than 20% opacity as determined using EPA Method 9, or that are corrected within 1 hour after detection, shall not constitute a violation of this condition. [District Rule 2201]
6. 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]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services

N-645-38-0 : Jun 9 2011 11:53AM -- DEMARISF : Joint Inspection NOT Required

7. PM10 emissions from the biomass fuel handling system, based on the quantity of fuel processed through the fuel metering bins, shall not exceed 0.000203 lb/ton on a daily average basis and 0.000227 lb/ton on an annual average basis. [District Rule 2201]

8. The quantity of fuel processed through the fuel metering bins shall not exceed 1,951 tons in any one day and 470,080 in any calendar year. [District Rule 2201]

9. Permittee shall maintain records of the quantity of biomass fuel processed through the fuel metering bins each day, in tons. [District Rule 2201]

10. Records shall be retained on-site for a period of at least five years and made available for District inspection upon request. [District Rule 2201]

11. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

12. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

13. When handling bulk materials outside an enclosed structure or building, water or chemical/organic stabilizers/suppressants shall be applied as required to limit Visible Dust Emissions to a maximum of 20% opacity. When necessary to achieve this opacity limitation, wind barriers with less than 50% porosity shall also be used. [District Rules 2201, 8011, and 8031]

14. When transporting bulk materials outside an enclosed structure or building, all bulk material transport vehicles shall limit Visible Dust Emissions to 20% opacity by either limiting vehicular speed, maintaining sufficient freeboard on the load, applying water to the top of the load, or covering the load with a tarp or other suitable cover. [District Rules 8011 and 8031]

15. All outdoor chutes and conveyors shall be controlled by any of the following options: 1) full enclosure, 2) operation with water spray equipment that sufficiently wets materials to limit VDE to 20% opacity, or 3) the concentration of particles having an aerodynamic diameter of 10 microns or less in the conveyed material shall be sufficiently small to limit VDE to 20% opacity. [District Rules 2201, 8011, and 8031]

16. 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 8041]

17. 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]

18. 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]

19. 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]

20. 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]

CONDITIONS CONTINUE ON NEXT PAGE

21. 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]

22. 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]

23. 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]

24. 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]

25. 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]

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-39-0 **ISSUANCE DATE:** 06/09/2011

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
BIOMASS RECEIVING OPERATION WITH THREE TRUCK UNLOADING HOPPERS, A DISC SCREEN AND HOGGER, AND ASSOCIATED CONVEYORS, AND BIOMASS STORAGE OPERATION WITH UP TO 2.1 ACRES OF BIOMASS STORAGE PILES

CONDITIONS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202]
4. All stockpiled biomass shall be covered, or maintained adequately moist, to prevent visible emissions in excess of 20% opacity as determined using EPA Method 9. Permittee shall use water sprays or other dust suppression techniques as necessary to ensure compliance with this opacity limit. [District Rule 2201]
5. Visible emissions from the disc screen, fuel hogger, and all conveyor transfer points shall not exceed 20% opacity as determined using EPA Method 9. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DAVID WARNER, Director of Permit Services
N-645-39-0 : Jun 9 2011 11:53AM – DEMARISF : Joint Inspection NOT Required

6. Permittee shall monitor the disc screen, fuel hogger, and all conveyor transfer points for visible emissions, as determined using EPA Method 22 on a daily basis. Daily monitoring shall take place at an appropriate time each day depending on plant start time and sunrise, but shall in any event be conducted before 12:00 PM. If visible emissions are detected, permittee shall take corrective action and eliminate visible emissions within 1 hour after detection. If visible emissions cannot be eliminated within 1 hour after detection, a visible emissions test using EPA Method 9 shall be conducted while the visible emissions are ongoing to determine if the visible emissions exceed the limits specified in this permit. Visible emissions less than 20% opacity as determined using EPA Method 9 shall not constitute a violation of this condition. [District Rule 2201]

7. 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]

8. PM10 emissions from the biomass fuel receiving operation shall not exceed 0.000539 lb/ton on a daily average basis and 0.000557 lb/ton on an annual average basis. [District Rule 2201]

9. Biomass fuel received by the receiving and storage operation shall not exceed 2,732 tons in any one day and 470,080 tons in any calendar year. [District Rule 2201]

10. Emissions from the biomass fuel storage piles shall not exceed 0.24 lb-PM10 per acre of fuel storage piles per day. [District Rule 2201]

11. Permittee shall maintain records of the quantity of biomass fuel received each day, in tons. [District Rule 2201]

12. Records shall be retained on-site for a period of at least five years and made available for District inspection upon request. [District Rule 2201]

13. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

14. Permittee shall submit an application to comply with District Rule 2520 - Federally Mandated Operating Permits prior to commencing operation under this ATC. [District Rule 2520]

15. When handling bulk materials outside an enclosed structure or building, water or chemical/organic stabilizers/suppressants shall be applied as required to limit Visible Dust Emissions to a maximum of 20% opacity. When necessary to achieve this opacity limitation, wind barriers with less than 50% porosity shall also be used. [District Rules 2201, 8011, and 8031]

16. When storing bulk materials outside an enclosed structure or building, water or chemical/organic stabilizers/suppressants shall be applied as required to limit Visible Dust Emissions to a maximum of 20% opacity. When necessary to achieve this opacity limitation, all bulk material piles shall also be either maintained with a stabilized surface as defined in Section 3.58 of District Rule 8011, or shall be protected with suitable covers or barriers as prescribed in Table 8031-1, Section B, of District Rule 8031. [District Rules 2201, 8011, and 8031]

17. When transporting bulk materials outside an enclosed structure or building, all bulk material transport vehicles shall limit Visible Dust Emissions to 20% opacity by either limiting vehicular speed, maintaining sufficient freeboard on the load, applying water to the top of the load, or covering the load with a tarp or other suitable cover. [District Rules 8011 and 8031]

18. All outdoor chutes and conveyors shall be controlled by any of the following options: 1) full enclosure, 2) operation with water spray equipment that sufficiently wets materials to limit VDE to 20% opacity, or 3) the concentration of particles having an aerodynamic diameter of 10 microns or less in the conveyed material shall be sufficiently small to limit VDE to 20% opacity. [District Rules 2201, 8011, and 8031]

19. 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 8041]

20. 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]

CONDITIONS CONTINUE ON NEXT PAGE

21. 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]
22. 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]
23. 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]
24. 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]
25. 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]
26. 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]
27. 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]
28. 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]
29. Upon implementation of this Authority to Construct, ATC N-645-37-0 shall be cancelled. [District Rule 2201]

Appendix C
Permits to Operate for the Coal-Fired Power Plant

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-645-8-4 **EXPIRATION DATE:** 11/30/2010

EQUIPMENT DESCRIPTION:
LIMESTONE RECEIVING SILO #1 CONTROLLED WITH A FABRIC FILTER BAGHOUSE

PERMIT UNIT REQUIREMENTS

1. Limestone shall be received through direct coupled pneumatic unloading truck. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The pneumatic transfer components and connections shall be totally air tight. [District NSR Rule] Federally Enforceable Through Title V Permit
3. The storage silos shall be totally air tight and vented only through a fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
4. The fabric filters shall have a maximum effective air to cloth ratio of 4.5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
5. There shall be no visible emissions from the fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
6. The fabric filter baghouse shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. The differential pressure across each compartment shall be maintained between 1" and 8" water column. [District NSR Rule and 2520, 9.3.2] Federally Enforceable Through Title V Permit
7. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit
8. Fabric collection system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
9. Fabric collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
10. Records of fabric collector system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual Performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit
11. Visible emissions from the the limestone receiving silo shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

12. The differential pressure across each compartment of the fabric filter baghouse shall be checked and the results recorded annually. If the differential pressure across each compartment of the fabric filters is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.] Federally Enforceable Through Title V Permit
13. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
14. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-645-9-4 **EXPIRATION DATE:** 11/30/2010

EQUIPMENT DESCRIPTION:
LIMESTONE RECEIVING SILO #2 CONTROLLED WITH A FABRIC FILTER BAGHOUSE

PERMIT UNIT REQUIREMENTS

1. Limestone shall be received through direct coupled pneumatic unloading truck. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The pneumatic transfer components and connections shall be totally air tight. [District NSR Rule] Federally Enforceable Through Title V Permit
3. The storage silos shall be totally air tight and vented only through a fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
4. The fabric filters shall have a maximum effective air to cloth ratio of 4.5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
5. There shall be no visible emissions from the fabric filter. [District NSR Rule] Federally Enforceable Through Title V Permit
6. The fabric filters shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. [District NSR Rule] Federally Enforceable Through Title V Permit
7. The differential pressure across the fabric filters baghouse shall be maintained between 1" and 8" water column. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
8. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit
9. Fabric collection system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
10. Fabric collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
11. Records of fabric collector system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual Performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit
12. Visible emissions from the the limestone receiving silo shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

13. The differential pressure across each compartment of the fabric filters shall be checked and the results recorded annually. If the differential pressure across each compartment of the fabric filters is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

14. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

15. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-645-10-4 **EXPIRATION DATE:** 11/30/2010

EQUIPMENT DESCRIPTION:
3.5 TON LIMESTONE/DAY TANK #1 CONTROLLED WITH A FABRIC FILTER BAGHOUSE

PERMIT UNIT REQUIREMENTS

1. Each silo shall be totally enclosed and vented only through a vent filter. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The bin vent filter shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. The differential pressure across each compartment shall be maintained between 1" and 8" water column. [District NSR Rule and 2520, 9.3.2] Federally Enforceable Through Title V Permit
3. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit
4. Limestone shall be transferred through a totally air tight pneumatic transfer system, only. [District NSR Rule] Federally Enforceable Through Title V Permit
5. The vent filter shall have a maximum air to cloth ratio of 5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
6. There shall be no visible emissions from the vent filter. [District NSR Rule] Federally Enforceable Through Title V Permit
7. Vent filter system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
8. Vent filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
9. Records of vent filter system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit
10. Visible emissions from the the limestone/day tank shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

11. The differential pressure across each compartment of the bin vent filter shall be checked and the results recorded annually. If the differential pressure across each compartment of the fabric filters is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

12. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

13. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-645-11-4 **EXPIRATION DATE:** 11/30/2010

EQUIPMENT DESCRIPTION:
3.5 TON LIMESTONE/DAY TANK #2 CONTROLLED WITH A FABRIC FILTER BAGHOUSE

PERMIT UNIT REQUIREMENTS

1. Each silo shall be totally enclosed and vented only through a vent filter. [District NSR Rule] Federally Enforceable Through Title V Permit
2. The bin vent filter shall be equipped with a pressure differential gauge to indicate the pressure drop across the bags. The gauge shall be maintained in good working condition at all times. The differential pressure across each compartment shall be maintained between 1" and 8" water column. [District NSR Rule and 2520, 9.3.2] Federally Enforceable Through Title V Permit
3. A spare set of each type of bags shall be maintained on the premises at all times. [District NSR Rule] Federally Enforceable Through Title V Permit
4. Limestone shall be transferred through a totally air tight pneumatic transfer system, only. [District NSR Rule] Federally Enforceable Through Title V Permit
5. The vent filter shall have a maximum air to cloth ratio of 5:1 and shall be equipped with an automatic pulse jet cleaning mechanism. [District NSR Rule] Federally Enforceable Through Title V Permit
6. There shall be no visible emissions from the vent filter. [District NSR Rule] Federally Enforceable Through Title V Permit
7. Vent filter system shall be completely inspected annually while in operation for evidence of particulate matter leaks and shall be repaired as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
8. Vent filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit
9. Records of vent filter system maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit
10. Visible emissions from the the limestone/day tank shall be checked and the results recorded annually. If visible emissions are observed, corrective action shall be taken prior to further operation of the equipment. Corrective action means that visible emissions are eliminated before operation of the equipment is resumed. If visible emissions cannot be corrected within 24 hours, a visible emissions test shall be conducted by a trained observer using EPA method 9 within 72 hours. A record of the results of these observations shall be maintained. Such records shall include the observer's name and affiliation, the date, time, sky condition, and the observer's location relative to the source. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

11. The differential pressure across each compartment of the bin vent filter shall be checked and the results recorded annually. If the differential pressure across each compartment of the vent filter is not between 1" and 8" water column, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2520, 9.3.2 and 9.4.2] Federally Enforceable Through Title V Permit
12. Particulate matter emissions shall not exceed 0.1 gr/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
13. Particulate matter emissions shall not exceed the hourly rate as calculated in District Rule 4202 using the equation E = 3.59xP^0.62 if P is less than or equal to 30 tons per hour, or E = 17.31xP^0.16 if P is greater than 30 tons per hour. [District Rule 4202] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-645-34-2 **EXPIRATION DATE:** 11/30/2010

EQUIPMENT DESCRIPTION:
43,000 GALLONS PER MINUTE COOLING TOWER

PERMIT UNIT REQUIREMENTS

1. The VOC emissions from the cooling tower shall not exceed 28.5 pounds in any one day. [District NSR Rule] Federally Enforceable Through Title V Permit
2. Permittee shall maintain a log recording the amount of VOC containing material added each day. [District NSR Rule] Federally Enforceable Through Title V Permit
3. A list of materials added to the cooling tower and their VOC content shall be kept and made available for District inspection upon request. [District NSR Rule] Federally Enforceable Through Title V Permit
4. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Appendix D
Boiler BACT Analysis from District Project N-1101175

San Joaquin Valley Air Pollution Control District
Revised BACT Determination
Biomass-Fired Boiler

Facility Name:	DTE Stockton, LLC	Date:	April 28, 2011
Mailing Address:	2526 W. Washington St. Stockton, CA 95203	Engineer:	Frank DeMaris
		Lead Engineer:	Rupi Gill
Contact Person:	Steven Sorrentino		
Telephone:	(734) 302-4893		
Fax:	(734) 302-4802		
E-Mail:	sorrentinos@dteenergy.com		
Application #:	N-645-8-5, '-9-5, '-10-5, '-11-5, '-34-4, '-36-0, '-37-0, '-38-0		
Project #:	N-1101175		
Deemed Complete:	May 11, 2010		

I. Proposal

DTE Stockton, LLC ("DTE") owns and operates a 54 MW coal-fired electrical generating station operating under Permit to Operate (PTO) N-645 with a total of 19 distinct permit units. DTE requests Authority to Construct (ATC) permits that will allow it to convert the facility to a biomass-fired generating station. Toward this end, the existing circulating fluidized bed (CFB) boilers (N-645-14 and N-645-16) will be removed from service, to be replaced by a single stoker-type boiler better suited to reliable biomass combustion. Existing fuel receiving and handling operations will be consolidated into a receiving and storage operation and a fuel handling operation, while the existing limestone receiving and day tanks will be converted to handle trona as an alternative acid gas control mechanism.

The potential emissions from the proposed new boiler will exceed 2.0 pounds per day for all pollutants. In addition, carbon monoxide (CO) emissions from this stationary source will exceed 200,000 pounds per year. Therefore, the best available control technology (BACT) requirements are triggered for all pollutants from this boiler. The District's BACT Clearinghouse includes an existing BACT Guideline (Guideline 1.3.2) for a biomass-fired bubbling fluidized bed combustor. The District has determined that this guideline must be revised and broadened to cover biomass-fired boilers in general, and to apply to any biomass-fired boiler with heat input sufficient to support 10 MW of electrical generation.

II. Location

This facility is located at 2526 W. Washington St. in Stockton, California, within the Port of Stockton. The District has determined that this facility is not within 1,000 feet of the outer boundary of the nearest K-12 school. Therefore, the school notification requirements of California Health & Safety Code 42301.6 do not apply to this application.

III. Equipment Description

N-645-36-0:
54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, TRONA INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

IV. .Process Description

DTE is currently a 49.9 MW (net) coal-fired electrical generating station, originally issued Authority to Construct permits in 1985, that uses two 280 MMBtu/hr CFB boilers. As part of the conversion of the facility from coal to biomass, the existing CFB boilers will be replaced with a single 699 MMBtu/hr stoker-type boiler. The applicant proposed the stoker-type boiler after concluding that this configuration offers somewhat greater operational readiness and slightly lower maintenance cost than the CFB configuration.

Biomass fuel, consisting primarily of agricultural biomass but possibly including urban wood waste, almond shells, and other biomass sources, will be delivered to the site by trucks. These trucks will be unloaded into truck unloading hoppers at the truck unloading station along West Washington Road. Conveyors with 3/4 covers will transport the fuel from the receiving area to a screen to remove oversize pieces, then through an electromagnet to remove metal, and finally to the biomass storage piles. A reclaim conveyor will reclaim biomass fuel from the storage piles and transfer it to enclosed conveyors, which will carry it to the four biomass metering bins. These metering bins are the last step before the biomass fuel enters the boiler fuel feed system.

The combustor is a stoker-type unit, meaning that fuel is burned on a grate as opposed to being burned in suspension or in a fluidized bed. The combustor is equipped with a vibrating grate, upon which fuel from the charging hopper is spread using a number of distribution devices. The vibrating grate consists of a series of grate elements in a horizontal arrangement. Half of the horizontal grate elements are fixed and half oscillate to move fuel along the grate toward the ash discharge. Combustion air is fed into the combustion chamber through ports located under each grate section, while overfire air enters the combustion chamber through additional ports spaced around the combustion chamber and arranged to ensure optimal mixing and complete combustion. Bottom ash, essentially all unburned fuel residue that is too massive to become entrained in the flue gas as fly ash, is removed from the stoker grate at the opposite end from the fuel charging hopper. Pursuant to the source category description presented in Section 2.2 of *Emission Factor Documentation for AP-42 Section 1.1: Bituminous and Subbituminous Coal Combustion* (where much of the information on solid fuel-fired boilers is available), this unit is classified as a spreader stoker.

For startup operations, the combustor is equipped with a 100 MMBtu/hr natural gas-fired startup burner. This will be used to gradually heat the boiler when starting up, in order to ensure the unit is not physically damaged by heat stresses, and to bring the combustion chamber up to sufficiently high temperature to allow the biomass fuel to ignite. Once the biomass fuel is ignited, the combustor will be gradually transitioned to firing exclusively on biomass fuel. The startup burner will also be utilized to complete combustion of any remaining solid fuel residue when shutting the unit down.

V. Best Available Control Technology (BACT)

SO_x emissions from fuel combustion are the result of fuel-bound sulfur being oxidized in the combustion process. DTE proposes to control SO_x emissions using a dry powder trona injection system. The trona powder adsorbs the gaseous SO_2 or SO_3, reacting with it to produce a sulfate that can be removed from the flue gas with the rest of the PM_{10}. Trona also has a similar affect on other acid gases, particularly HCl. However, because HCl is a hazardous air pollutant, DTE also proposes to use a wet scrubber for additional HCl control to ensure that the boiler is not a major source of hazardous air pollutants.

PM_{10} emissions from the combustor will be controlled using a combination of a multiclone and an ESP. In a multiclone, the flue gas is routed through several drastic course changes which cause suspended particulate matter to collide with the multiclone walls and fall out of suspension. In an ESP, the flue gas passes through the corona induced by an array of charged wires. Passing through the corona induces a charge on the particulate matter within the flue gas, which causes the particle to be drawn in the direction of an oppositely-charged collector plate, which it impacts and adheres to. When enough the material collected begins to interfere with the collection efficiency, the plates are rapped to cause the collected dust to fall off into a collection hopper.

CO and VOC emissions from the combustor are primarily the result of incomplete combustion. However, highly efficient combustion that minimizes CO and VOC emissions also tends to maximize NO_x emissions. DTE has proposed to control CO and VOC emissions using proper combustion supplemented by an oxidation catalyst. This catalyst uses excess oxygen in the flue gas to oxidize CO and VOC to CO_2 and gaseous H_2O.

Any operation that combusts fuel has the potential to result in NO_x emissions, which can come from the oxidation of fuel-bound nitrogen ("fuel NOx") or from the oxidation of nitrogen in the combustion air at high temperature ("thermal NO_x"). Fuel NO_x is largely, although not directly, proportional to the fuel nitrogen content, and therefore essentially fixed in the design phase. Thermal NO_x is a function of several variables, including peak combustion temperature, the residence time at peak temperature, nitrogen concentration, and oxygen concentration or flame stoichiometry. Combustion modifications can be useful in adjusting these variables by reducing the peak temperature, nitrogen concentration, and stoichiometry. For example, by injecting some combustion air below the grate and the rest of the combustion air through the overfire air ports above the grate, the combustion zone can be expanded and the peak temperature reduced.

NO_x can also be controlled using add-on control devices such as selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR). These techniques are similar in that they inject ammonia or urea into the flue gas in order to reduce NO_x to molecular nitrogen and water. SNCR requires high temperatures, between 1600 °F and 2100 °F, while SCR uses a catalyst to allow the same reaction to take place between 480 °F and 800 °F. SNCR has been used on biomass-fired boilers since the mid-1980s, so this control technology is well-known and widely applied. SCR is a well-known technology for controlling NO_x from gaseous or liquid fuel-fired boilers, but use on solid fuel-fired units is much more recent.

The District has recently sent draft ATCs for public notice requiring both SNCR and SCR for biomass-fired boilers. However, none of these ATCs have been issued, and in at least one case the application has been cancelled. Furthermore, DTE has provided data from the SCR vendor strongly indicating that ammonia slip from an SNCR system may be oxidized across an oxidation catalyst, resulting in much lower net NO_x control from the SNCR than would be the case in the absence of an oxidation catalyst. The SCR vendor also argues that the oxidation catalyst is required both the comply with the CO and VOC emission limits and to allow the SCR catalyst an acceptable life, since the oxidation catalyst provides additional particulate control ahead of the SCR catalyst and is much sturdier and better able to withstand the rigors of operational use and cleaning than the SCR catalyst. Therefore, DTE proposes to use only combustion controls and SCR to control NO_x emissions.

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following[1]:

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

Emissions from this biomass-fired boiler are presented in the following table:

PE2 (lb/day)						
Unit	NO_x	SO_x	PM_{10}	CO	VOC	NH_3
Biomass-fired boiler	2,225.2	2,717.7	833.8	6,374.9	645.9	318.7

The boiler itself has the potential to emit 495,836 lb-CO/yr, which exceeds the threshold of 200,000 lb/yr required to trigger BACT for CO. In addition, the boiler has the potential to emit more than 2.0 lb/day of each pollutant. Therefore, the boiler triggers the BACT requirements for all affected pollutants. In addition, this unit triggers the toxics best available control technology (T-BACT) requirement for PM_{10} emissions. Since this unit also triggers BACT for PM_{10}, and T-BACT is equivalent to BACT for the pollutant(s) that trigger T-BACT, no specific T-BACT analysis for PM_{10} will be conducted.

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

2. BACT Policy

In accordance with District Policy APR-1305, *Best Available Control Technology (BACT) Policy*, Section IX, "A top-down BACT analysis shall be performed as a part of the Application Review for each application subject to the BACT requirements pursuant to the District's NSR Rule." For source categories or classes covered in the BACT Clearinghouse, relevant information under each of the steps may be simply cited from the Clearinghouse without further analysis.

Existing BACT Guideline 1.3.2, which was developed to cover a biomass-fired bubbling fluidized bed combustor, is the most applicable guideline and will be cited in this determination. However, the published version of this guideline in the District's BACT Clearinghouse was last updated in November of 2002, so the guideline requires an update to consider more recent permitting actions, compliance demonstrations, and technological innovations.

The District began working on an update to this guideline as part of project C-1090203, a proposal for four biomass-fired boilers associated with the San Joaquin Solar project. However, although this project received preliminary approval from the District (public notice of the preliminary decision being published on October 12, 2009), the application was cancelled by the applicant prior to issuance of the ATCs. The updated BACT guideline was never published in the District's BACT Clearinghouse. A second application, project N-1094135, was evaluated under the revised BACT Guideline and released for public notice of the preliminary approval (on July 12, 2010). This application is currently on hold for reasons beyond the District's control, so no final approval can be given.

DTE and its control equipment vendors were made aware of the revision to BACT Guideline 1.3.2 following submission of the application packet. After reviewing the revised guideline and the two recent projects working from it (C-1090203 and N-1094135), DTE and its vendors have submitted comments and technical data calling into question some of the assumptions and analysis presented in these earlier projects. While these comments do not invalidate the earlier work, they do suggest that the collection of more operational data is warranted in order to substantiate the more aggressive emission limits in those earlier projects. Furthermore, these comments emphasize the fact that, for many of the pollutants involved, data regarding the application of these control devices to this class and category of source operation is extremely limited. For example, SNCR is a very common NO_x control device for biomass-fired boilers, SCR has a much shorter track record, and the combination of the two controls is, at this time, purely a theoretical exercise. Therefore, DTE's comments and analysis must be taken into consideration in revising the BACT Guideline, and future revisions to the guideline will hopefully benefit from DTE's operational experience with these controls.

3. Top-Down BACT Determination

EPA's RACT/BACT/LAER Clearinghouse database, CARB's BACT Clearinghouse database, the Bay Area Air Quality Management District (BAAQMD) BACT Clearinghouse, the South Coast Air Quality Management District (SCAQMD) BACT Clearinghouse, and the San Diego Air Pollution Control District (SDAPCD) BACT Clearinghouse were also queried for BACT requirements for biomass-fired boilers. In addition, in 2007 the Massachusetts Department of Environmental Protection published an internal memorandum discussing the BACT requirements for biomass-fired boilers (the "DEP memo"), which was consulted.

NO_x BACT:

BACT is triggered for NO_x emissions from this biomass-fired boiler.

Step 1 – Identify All Possible Control Technologies:

The following NO_x controls and associated emission limits have been developed from the various BACT Clearinghouses, the DEP memo, and the existing District BACT Guideline:

1. 0.10 lb/MMBtu (ammonia injection and natural gas auxiliary fuel) – Achieved in Practice (existing BACT Guideline 1.3.2)
2. 0.075 lb/MMBtu (regenerative selective catalytic reduction (RSCR), or equal, and natural gas auxiliary fuel) – Achieved in Practice (DEP memo)
3. 0.065 lb/MMBtu (selective catalytic reduction (SCR), or equal, and natural gas auxiliary fuel) – Technologically Feasible (Applicant's proposal)
4. 0.060 lb/MMBtu (RSCR or equal) – Technologically Feasible (Connecticut Department of Environmental Protection, Permit 107-0056)
5. 0.012 lb/MMBtu, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and wet scrubber, or equal, and natural gas auxiliary fuel – Technologically Feasible (District projects C-1090203 and N-1094135)

While data from the RACT/BACT/LAER clearinghouse indicates other emission limits are available for consideration, these limits have not been found to be consistent with the District's practice, as expressed in District Rule 4352, of limiting NO_x emissions from solid fuel-fired boilers on a block 24-hour average basis. For example, the New Hampshire Department of Environmental Services issued permit TP-0054 on July 26, 2010 for a 70 MW (1,013 MMBtu/hr) biomass-fired boiler with a NO_x emission limit of 0.06 lb/MMBtu. However, this limit, achieved using an SCR system downstream from the baghouse, is expressed as a 30-day rolling average limit. By its nature, biomass is a non-homogenous fuel that is likely to have physical and combustion characteristics that vary substantially over time, in comparison with fuels such as natural gas or coal, that have much more homogenous physical and combustion characteristics. This variability in combustion characteristics produces a corresponding variability in NO_x emissions over time, such that a short-term NO_x emission limit must necessarily be higher than an emission limit with a longer averaging period. Indeed, the averaging period is an essential element of any emission limit under consideration in a BACT determination. Therefore, the existence of lower emission limits in a pre-construction approval issued by another agency cannot automatically invalidate higher emission limits under consideration in this document when those lower limits use a longer averaging period.

In addition, it is noted that the Georgia Department of Natural Resources (DNR) issued a permit for a new 1,529 MMBtu/hr biomass-fired boiler with a NO_x emission limit, as entered in the RACT/BACT/LAER clearinghouse, of 0.01 lb/MMBtu on a 30-day rolling average. However, this entry is clearly a typographical error as indicated by the unit's potential emissions and description as a bubbling fluidized bed combustor with SNCR, and confirmed by the Air Quality Permit issued by the Georgia DNR, which limits NO_x emissions to 0.10 lb/MMBtu on a 30-day rolling average basis.

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 have been found to be technologically feasible, either by another regulatory agency or by applicants for District permits. However, it must be noted that the District's acceptance of 0.012 lb-NO_x/MMBtu as technologically feasible is based on ATC applications that proposed this emission limit, but in neither of the previous projects (N-1094135 and C-1090203) has an ATC been issued. Instead, project C-1090203 was cancelled at the applicant's request, while project N-1094135 is still in review pending satisfaction of the California Environmental Quality Act requirements by the Lead Agency[2].

The vendor for the proposed SCR system has raised the possibility that ammonia injection, such as for SNCR, upstream of the oxidation catalyst may lead to an increase in NO_x emissions as ammonia is oxidized to NO_x by the oxidation catalyst. Excess ammonia is likely to be oxidized across the oxidation catalyst at a ratio of 1 ppmv of additional NO_x for each ppmv of ammonia slip. The vendor estimates that an SNCR system, working from an uncontrolled emission factor of 0.33 lb/MMBtu (based on data from DTE's Woodland plant) would reduce NO_x by approximately 40% to 0.20 lb/MMBtu. At 40 ppmv of ammonia slip from the SNCR system, the vendor estimates approximately 0.08 lb/MMBtu of additional NO_x would be generated, for a total of 0.28 lb/MMBtu. The net effect of the SNCR system would be reduced to approximately 15% control efficiency once oxidation of ammonia across the oxidation catalyst is taken into account.

Furthermore, it is not feasible to simply abandon the oxidation catalyst in favor of SNCR and additional NO_x reductions, both because the oxidation catalyst is required for compliance with the proposed VOC and CO emission limits and because the oxidation catalyst serves an important supporting function for the SCR system. The SCR catalyst is constructed of a fibrous material with a comparatively thick catalyst bed, whereas the oxidation catalyst is metallic in construction with a comparatively thin catalyst bed. The metallic oxidation catalyst is sturdier than the fibrous SCR catalyst, while the thinner catalyst bed on the oxidation catalyst is easier to keep clean than the thick catalyst bed on the SCR catalyst. This combination of ruggedness and easy cleaning allows the oxidation catalyst to serve a protective function for the SCR catalyst, shielding the latter from the particulate matter still in the exhaust stream. This protective function for the oxidation catalyst is expected to allow the SCR catalyst a significantly longer life with less maintenance and fewer excursions above the emission limit.

If the technologically feasible limit of 0.012 lb/MMBtu is revised to remove the expected 40% control efficiency, the result is 0.02 lb/MMBtu. Assuming 90% control efficiency from the SCR system, the uncontrolled emissions would be approximately 0.2 lb/MMBtu, which is a significantly lower starting point than the 0.33 lb/MMBtu experienced at DTE's Woodland plant. Therefore, while the District believe that this emission limit is technologically feasible in general, 0.012 lb/MMBtu cannot be considered to represent a technologically feasible emission limit for the proposed combination of fuel, combustor, and pollution controls associated with this proposal.

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[2] It is worth noting that the Governing Board for the Modesto Irrigation District, which is the Lead Agency for project N-1094135, voted to terminate negotiations with the project proponent on October 12, 2010.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 0.065 lb/MMBtu (SCR for 90% control or equal and natural gas auxiliary fuel)
2. 0.060 lb/MMBtu, (RSCR for 70% control or equal and natural gas auxiliary fuel)
3. 0.075 lb/MMBtu, regenerative selective catalytic reduction (RSCR) or equal, and natural gas auxiliary fuel

It must be noted that the emission limit of 0.060 lb/MMBtu found to be technologically feasible by the Connecticut DEP is based on a control efficiency of 70% for the regenerative SCR included in that proposal. In contrast, DTE has proposed an SCR system with 90% control efficiency, albeit with a higher uncontrolled emission factor that leads to a slightly higher controlled emission limit. If the RSCR at 70% control efficiency were applied to the proposed boiler, the resulting emission limit would be:

EF = (0.33 lb/MMBtu) x (1 – 0.70) = 0.099 lb/MMBtu

Since BACT is defined as the most stringent emission limit or control technique from the list of possibilities specified in Rule 2201, Section 3.9, 90% control of NO_x emissions using SCR must be considered a more stringent control technique than 70% control using RSCR.

While 0.10 lb/MMBtu would be the 4th item in this list, it is an “achieved in practice” level of control that is less stringent than the other “achieved in practice” emission limit of 0.075 lb/MMBtu. Therefore, 0.10 lb/MMBtu will be removed from consideration at this time.

Step 4 – Cost Effectiveness Analysis

The applicant has proposed the most stringent emission limitation remaining from Step 3. No cost effectiveness analysis is required.

Step 5 – Select BACT

The BACT requirement is satisfied by the applicant’s proposal to comply with an emission limit of 0.065 lb-NO_x/MMBtu using selective catalytic reduction for 90% control of NO_x emissions and natural gas as auxiliary fuel.

In addition, as part of their application DTE has proposed, and the District has approved, a lower NO_x emission target of 0.040 lb/MMBtu based on 90% control from an uncontrolled emission rate of 0.33 lb/MMBtu, plus a compliance margin of approximately 20%. DTE will be granted a 24-month evaluation period in which to gather operational and emissions data on the boiler and SCR system. At the end of the evaluation period, DTE will submit a report using all available data to show what emission limit the boiler and control system can reliably comply with. DTE will then submit an application to revise the NO_x emission limit based on the results of the report. If DTE fails to submit the report, the NO_x emission target of 0.040 lb/MMBtu will become an enforceable emission limit, displacing the current NO_x emission limit of 0.065 lb/MMBtu. Furthermore, as this operational and emissions data becomes available, the District will proactively update BACT Guideline 1.3.2 to reflect that data.

SO_x BACT:

BACT is triggered for SO_x emissions from this biomass-fired boiler.

Step 1 – Identify All Possible Control Technologies:

1. 23 ppmvd (limestone injection and natural gas auxiliary fuel) – Achieved in Practice (BACT Guideline 1.3.2)
2. 0.025 lb/MMBtu (limestone injection, or equivalent equipment, and natural gas auxiliary fuel) – Achieved in Practice (DEP memo)
3. 0.012 lb/MMBtu (limestone injection, or equivalent equipment, and natural gas auxiliary fuel) – Technologically Feasible (District projects C-1090203 and N-1094135)

Note that 23 ppmvd SO_x @ 3% O_2 is equivalent to 0.0384 lb-SO_x/MMBtu, as determined in project S-1020710.

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 have been found to be technologically feasible, either by another regulatory agency or by applicants for District permits. However, it must be noted that the limit of 0.025 lb/MMBtu is based on the DEP memo, which concluded that the current achieved in practice BACT for SO_x is 0.025 lb/MMBtu based on the permits for several biomass-fired boilers in nearby states[3]. The District has reviewed the permits for the listed boilers and concluded that only one, PSNH – Schiller Station Unit 5 in Portsmouth, New Hampshire, actually includes this emission limit.

Schiller Station unit 5 is permitted to fire on both biomass and coal, with a separate SO_x emission limit for each fuel, and is equipped with limestone injection for use when firing on coal. When firing on biomass, the Schiller Station boiler operates without the limestone injection, so the SO_x emissions are entirely uncontrolled. Furthermore, Schiller Station's biomass fuel is primarily wood from timber harvesting, fire control debris removal, sawmill residue, and the clearing of forested land for development. In contrast, DTE proposes to fire primarily on agricultural residue and urban wood waste and expects, based on data from a unit in Woodland firing on similar fuel, to burn fuel with sufficient sulfur to result in uncontrolled emissions of 0.13 lb/MMBtu on average, peaking at 0.27 lb/MMBtu for the worst-case fuel. Therefore Schiller Station unit 5 cannot be considered to provide a valid point of comparison for the proposed new boiler, and the limit of 0.025 lb/MMBtu cannot be considered achieved-in-practice for this category of source.

It is noted that the emission factor associated with the achieved in practice control calculated above is greater than the alternative achieved in practice emission factor of 23 ppmvd @ 3% O_2, equivalent to 0.0384 lb/MMBtu. However, the District notes that this emission limit comes from permits to operate S-75-6-28 and S-75-11-24, originally established in 1996 as part of project S-961126, and appears to be based in part on a condition limiting fuel sulfur content to 0.90% by weight. Uncontrolled emissions based on this fuel sulfur content limit would be approximately 3.13 lb/MMBtu, requiring a control efficiency of 98.8% to comply with the

[3] Schiller Station in Portsmouth, NH, Whitefield Power in Whitefield, NH, Boralex in Stratton, ME, Ware Cogen in Ware, MA, and McNeil Station in Burlington, VT.

emission limit of 0.0384 lb/MMBtu. Since such high control efficiency is beyond the range of control efficiencies (50 – 80%) normally ascribed to a dry sorbent injection process, and near the limits of what a wet flue gas desulfurization system would be capable of, additional investigation of these emission limits is required.

It is worth noting that these units are required to source test for SO_x once each year, and the most recent source test results show these units emitting 0.22 and 0.47 ppmvd SO_x @ 3% O_2; these results are less than 2% of the permitted emission limit. The high control efficiency necessary for compliance from an assumed fuel sulfur content of 0.9%, along with the extremely high current margin for compliance, strongly suggest that the uncontrolled SO_x emissions from each of these units is already in compliance with the emission limit. For example, assuming limestone injection provides 80% control of SO_x emissions, the uncontrolled emissions are:

EF = (0.47 ppmv) ÷ (1.00 – 0.80) = 2.4 ppmv

This suggests the uncontrolled emission factor is far lower than the emission limit, which is far lower than the uncontrolled emission factor proposed for DTE Stockton based on data from DTE's Woodland facility. Furthermore, the fuel sulfur content limit of 0.9% was associated with only a few fuel sources, such as cotton stalks and cotton gin trash, which the facility now consciously avoids because of the high sulfur content. Therefore, the boilers at facility S-75 cannot be considered to provide a valid point of comparison for the proposed new boiler either.

BACT is defined as the most stringent emission limit or control technique from a list of options specified in Rule 2201, Section 3.9. The applicable emission limit must be determined from the control technique and the uncontrolled emissions, so as the uncontrolled emissions increase, the emission limit resulting from application of the most stringent control technique must also increase. US EPA and the Environmental Appeals Board have long maintained that it is inappropriate to utilize the BACT requirement to fundamentally redefine the basic design or scope of the proposed project. DTE proposes to construct a biomass-fired boiler that will be fueled using locally-available biomass fuels from agricultural and urban wood sources. Similar biomass fuels are used at the Woodland plant and the potential fuel sulfur content of those fuels are a given in the project design. Requiring DTE to use fuels with lower sulfur contents would constitute a redefinition of the project scope so that it would no longer use locally-available biomass fuels. Therefore, the achieved-in-practice BACT must be considered to be limestone injection or equivalent equipment, which can achieve control efficiency in excess of 80% in many circumstances. The District will consider limestone injection with 80% control efficiency as the achieved-in-practice BACT for this category of source, and will calculate the emission limit from the uncontrolled emissions provided by the applicant.

EF = (0.27 lb/MMBtu) x (1 – 0.80) = 0.054 lb/MMBtu

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 0.012 lb/MMBtu (limestone injection, or equivalent equipment, and natural gas auxiliary fuel)
2. 0.054 lb/MMBtu (limestone injection, or equivalent equipment, and natural gas auxiliary fuel)

Step 4 – Cost Effectiveness Analysis

DTE has proposed an emission limit of 0.054 lb/MMBtu on a block 24-hour average basis, which is the achieved-in-practice level of SO_x control for this class and category of source. DTE has provided cost estimates from control equipment vendors to address the question of whether the additional wet scrubber required for compliance with an emission limit of 0.012 lb/MMBtu would be cost effective. It is noted that this emission limit would require the control efficiency to exceed 95% to ensure that even the worst-case fuel did not cause a violation of the emission limit. This control efficiency is well in excess of what can be achieved by dry scrubbers such as the proposed trona injection system, so a wet scrubber must be considered.

DTE submitted the estimated capital cost for a wet scrubber system, and associated systems to recover and dispose of the sulfate solids in the wet scrubber solution. These costs are estimated at $5,800,000, which can be annualized over 10 years at 10% interest as follows:

$C_{capital}$ = (\$5,800,000) x $[(0.1) \times (1 + 0.1)^{10}] \div [(1 + 0.1)^{10} - (1)]$ = (\$5,800,000) x (0.1627)
$C_{capital}$ = \$944,000/yr

In addition, such a scrubber would have additional electrical costs, reagent costs, solid waste disposal costs, and labor costs. Of these additional costs, DTE has provided an estimate of $642,000 per year for the sodium hydroxide reagent used in the scrubber. The total annual cost is calculated by adding the annual operating cost to the annualized capital cost:

$C_{total} = C_{capital} + C_{operating}$ = (\$944,000/yr) + (\$642,000/yr) = \$1,586,000/yr

Cost effectiveness is calculated by dividing the annual cost by the annual emission reductions from District standard emissions. Pursuant to the May 2008 Memorandum revising the cost effectiveness thresholds for BACT determinations, when a new unit is not subject to a prohibitory rule limiting emissions of a particular pollutant then District standard emissions are equal to the emissions from similar equipment commonly available within the District. This biomass-fired boiler is subject to SO_x emission limits in Rules 4301 and 4801; however, these rules were last amended in 1992 and cannot be taken to represent District standard emissions in 2010. Therefore, a survey of biomass-fired boilers within the District is appropriate for establishing District standard emissions.

Survey of SO_x Emission Limits for District Biomass-Fired Boilers			
Unit	Emission Limit (lb/hr)	Heat Input (MMBtu/hr)	Equivalent EF (lb/MMBtu)
N-1026-1-10	6.25	259	0.024
C-799-3-13	29	460	0.063
C-1820-1-24	10.0	352	0.028
C-825-5-10	10.3	317	0.032
S-285-2-4	9.90	149	0.066
S-75-6-28	15.66	400	0.039
S-75-11-24	12.09	315	0.038
N-4607-8-0	N/A, SO_x emission limit is directly specified on a lb/MMBtu basis.		0.035
C-6923-3-0			0.04
S-834-3-6			0.061
S-91-3-14			0.04

The average SO_x emission limit from Table C-1 above is 0.042 lb/MMBtu. This conclusion is reinforced by the fact that the mode (most common result) for SO_x emission factors in the table is 0.04 lb/MMBtu, particularly if all emission factors are rounded to one significant digit. At one significant digit, five of the eleven biomass-fired boilers have a SO_x emission limit of 0.04 lb/MMBtu. Therefore, 0.042 lb-SO_x/MMBtu will be taken as the District standard emission factor, allowing annual standard emissions to be calculated as follows:

PE2 = [(0.042 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.27 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 230,674 lb/yr

Potential emissions using the technologically feasible emission limit of 0.012 lb/MMBtu are calculated as follows:

PE2 = [(0.012 lb/MMBtu) x (641 MMBtu/hr) x (8,400 hr/yr)] + [(0.27 lb/MMBtu) x (24 hr/yr) x (699 MMBtu/hr)]
PE2 = 69,142 lb/yr

The cost per ton of emission reductions is calculated as follows:

$C_{reductions}$ = (\$1,586,000/yr) ÷ [(230,674 lb/yr – 69,142 lb/yr) x (1 ton/2,000 lb)] = \$19,637/ton

The cost effectiveness threshold for SO_x emission reductions specified in the May 2008 Memorandum is \$18,300/ton. The cost of reductions calculated above is \$19,637/ton, which is greater than the threshold. Note that this does not include operational expenses such as additional electricity consumption, additional labor costs, and additional solid waste disposal costs. If these costs were included, the annual cost would be even greater and the resulting emission reductions would cost even more on a dollar-per-ton basis. Therefore, the technologically feasible emission limit of 0.012 lb/MMBtu is not cost effective.

Although DTE has proposed to install a wet scrubber for HCl control, HCl emissions cannot be included in the cost effectiveness determination because BACT, or more precisely T-BACT, is not triggered for HCl. BACT is evaluated on a pollutant-by-pollutant basis, so it is entirely inappropriate to include pollutants for which BACT is not required in the evaluation of the cost effectiveness of controls for a pollutant for which BACT is required, even if the control device would also affect the pollutant for which BACT is not required.

Furthermore, the cost effectiveness evaluation above addresses the cost of SO_x emission reductions associated with adding a wet scrubber in order to determine whether the District can require compliance with a lower emission limit. The analysis shows that an additional wet scrubber is not a cost effective method of reducing SO_x emissions from the District standard of 0.042 lb/MMBtu to 0.012 lb/MMBtu, so the District cannot require DTE to comply with the lower emission limit. The fact that DTE has proposed a wet scrubber for HCl control is not germane to the determination that the District cannot require compliance with the lower emission limit because that limit cannot be complied with in a cost effective manner.

Step 5 – Select BACT

BACT is satisfied by DTE's proposal to use trona injection and natural gas auxiliary fuel to comply with a SO_x emission limit of 0.054 lb/MMBtu on a block 24-hour average basis. The District has concluded that trona injection provides SO_x control at least equivalent to limestone injection, and DTE will be required to conduct source testing and CEMS monitoring to support that conclusion by demonstrating compliance with the emission limit. No further discussion is required.

PM_{10} BACT:

BACT is triggered for PM_{10} emissions from this biomass-fired boiler.

Step 1 – Identify All Possible Control Technologies:

1. 0.045 lb/MMBtu (baghouse or ESP and natural gas auxiliary fuel) – Achieved in Practice (Guideline 1.3.2)
2. 0.024 lb/MMBtu (baghouse, multiclone, and wet scrubber, or equivalent equipment, and natural gas auxiliary fuel) – Technologically Feasible (District projects C-1090203 and N-1094135)
3. 0.0214 lb/MMBtu (multiclone and baghouse or ESP, or equivalent equipment, and natural gas auxiliary fuel) – Technologically Feasible (Applicant's proposal)

While the previous District projects found an emission limit of 0.024 lb-PM_{10}/MMBtu to be technologically feasible, the District has more recently become aware of at least three biomass-fired boilers in the State of Washington[4] that are permitted for, and in compliance with, an emission limit of 0.02 lb-PM_{10}/MMBtu. Review of the relevant permit conditions and test results shows that this emission limit includes both filterable and condensable PM_{10} and that the limit is valid to one significant digit, such that a test result of 0.024 lb-PM_{10}/MMBtu would not be a violation because it would round to one significant digit, i.e., it would round to 0.02 lb/MMBtu. Therefore, 0.024 lb-PM_{10}/MMBtu will be considered achieved in practice.

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 have been found to be technologically feasible, either by another regulatory agency or by applicants for District permits.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 0.0214 lb/MMBtu (multiclone and baghouse or ESP, or equivalent equipment, and natural gas auxiliary fuel)
2. 0.024 lb/MMBtu (baghouse, multiclone, and wet scrubber, or equivalent equipment, and natural gas auxiliary fuel)

The limit of 0.045 lb-PM_{10}/MMBtu will be removed from consideration as the less stringent of the two achieved in practice options.

Step 4 – Cost Effectiveness Analysis

DTE has proposed the most stringent emission limit in step 3. A cost effectiveness analysis is not required.

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[4] Hampton Lumber Mill in Darrington, WA; Sierra Pacific Industries in Burlington, WA; Sierra Pacific Industries in Aberdeen, WA.

Step 5 – Select BACT

BACT is satisfied by DTE's proposal to use a multiclone and ESP to comply with a PM_{10} emission limit of 0.0214 lb/MMBtu. No further discussion is required.

CO BACT:

BACT is triggered for CO emissions from this biomass-fired boiler.

Step 1 – Identify All Possible Control Technologies:

1. 183 ppmvd (natural gas auxiliary fuel) – Achieved in Practice (Guideline 1.3.2)[5]
2. 0.1 lb/MMBtu (natural gas auxiliary fuel) – Achieved in Practice (DEP memo)
3. 0.09 lb/MMBtu (oxidation catalyst and natural gas auxiliary fuel) – Technologically Feasible (Applicant's proposal)
4. 0.05 lb/MMBtu (natural gas auxiliary fuel) – Technologically Feasible (District projects C-1090203 and N-1094135)

It is noted that option 2, an emission limit of 0.1 lb-CO/MMBtu, is confirmed as achieved in practice by Schiller Station unit 5 in New Hampshire. This biomass-fired boiler is permitted for this emission limit, with confirmation of compliance provided by the continuous emissions monitoring system for CO emissions.

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 have been found to be technologically feasible, either by another regulatory agency or by applicants for District permits. However, it must be noted that the District has previously accepted 0.05 lb-CO/MMBtu as technologically feasible based on ATC applications that proposed this emission limit. The District acknowledges that in neither of the previous projects (N-1094135 and C-1090203) has an ATC been issued. Instead, project C-1090203 was cancelled at the applicant's request, while project N-1094135 is still in review pending satisfaction of the CEQA requirements by the Lead Agency.

The District has concluded that an oxidation catalyst will provide some level of CO control, resulting in an emission limit lower than the achieved-in-practice limit of 0.1 lb/MMBtu. However, in the absence of a manufacturer's guarantee or a permit condition confirmed by compliance testing, there would be insufficient data available for the District to conclusively determine exactly how low an emission limit an oxidation catalyst will allow. The District must, therefore, pay close attention to the guarantee offered by the oxidation catalyst manufacturer, which is for continuous compliance with an emission limit of 0.09 lb-CO/MMBtu; this emission limit will be evaluated as the only technologically feasible control option with any significant supporting documentation at this time.

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[5] Equivalent to 0.140 lb-CO/MMBtu as described in District project S-1020710.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 0.09 lb/MMBtu using an oxidation catalyst and natural gas auxiliary fuel
1. 0.1 lb/MMBtu using natural gas auxiliary fuel

The other achieved-in-practice control option of 183 ppmvd CO @ 3% O_2 (0.140 lb-CO/MMBtu) will be removed from consideration at this time as it is the less stringent of the two achieved in practice options.

Step 4 – Cost Effectiveness Analysis

DTE has proposed the most stringent emission limit in step 3. A cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied by DTE's proposal to use an oxidation catalyst and natural gas auxiliary fuel to comply with a CO emission limit of 0.09 lb/MMBtu. No further discussion is required.

VOC BACT:

BACT is triggered for VOC emissions from this biomass-fired boiler.

Step 1 – Identify All Possible Control Technologies:

1. 0.02 lb/MMBtu (natural gas auxiliary fuel) – Achieved in Practice (Guideline 1.3.2)
2. 0.01 lb/MMBtu (natural gas auxiliary fuel) – Achieved in Practice (DEP memo)
3. 0.009 lb/MMBtu (oxidation catalyst and natural gas auxiliary fuel) – Technologically Feasible (Applicant's proposal)
4. 0.005 lb/MMBtu using natural gas auxiliary fuel – Technologically Feasible (District projects C-1090203 and N-1094135)

Step 2 – Eliminate Technologically Infeasible Options:

All technologies listed in Step 1 have been found to be technologically feasible, either by another regulatory agency or by applicants for District permits. However, it must be noted that the District has previously accepted 0.005 lb-VOC/MMBtu as technologically feasible based on ATC applications that proposed this emission limit. The District acknowledges that in neither of the previous projects (N-1094135 and C-1090203) has an ATC been issued. Instead, project C-1090203 was cancelled at the applicant's request, while project N-1094135 is still in review pending satisfaction of the CEQA requirements by the Lead Agency. Furthermore, it is noted that Schiller Station unit 5, a biomass-fired boiler located in New Hampshire, is operating under a PSD permit that limits VOC emissions to 0.005 lb/MMBtu. However, this emission limit is unverified as the PSD permit includes no requirement for the operator to conduct testing and demonstrate compliance with the emission limit. Therefore, the limit of 0.005 lb/MMBtu cannot be considered achieved in practice at this time.

The District has concluded that an oxidation catalyst will provide some level of VOC control, resulting in an emission limit lower than the achieved-in-practice limit of 0.01 lb/MMBtu. However, it is noted that the Connecticut Department of Environmental Protection recently issued a permit for a biomass-fired boiler which limited VOC emissions to 0.01 lb/MMBtu using an oxidation catalyst. In the absence of a manufacturer's guarantee or a permit condition confirmed by compliance testing, there would be insufficient data available for the District to conclusively determine exactly how low an emission limit an oxidation catalyst will allow. The District must, therefore, pay close attention to the guarantee offered by the oxidation catalyst manufacturer, which is for continuous compliance with an emission limit of 0.009 lb-VOC/MMBtu; this emission limit will be evaluated as the only technologically feasible control option with any significant supporting documentation at this time.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

2. 0.009 lb/MMBtu (oxidation catalyst and natural gas auxiliary fuel)
3. 0.01 lb/MMBtu (natural gas auxiliary fuel)

The other achieved-in-practice control option of 0.02 lb-VOC/MMBtu will be removed from consideration at this time as it is the less stringent of the two achieved in practice options.

Step 4 – Cost Effectiveness Analysis

DTE has proposed the most stringent emission limit in step 3. A cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied by DTE's proposal to use an oxidation catalyst and natural gas auxiliary fuel to comply with a VOC emission limit of 0.009 lb/MMBtu. No further discussion is required.

Proposed Pages for the BACT Clearinghouse

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.3.2*

Emission Unit: Biomass-Fired Boiler **Industry Type:** Electrical Generation

Equipment Rating: ≥10 MW **Last Update:** TBD

	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_x	0.075 lb/MMBtu, block 24-hour average (Regenerative Selective Catalytic Reduction, or equal, and natural gas auxiliary fuel)	0.065 lb/MMBtu, block 24-hour average (Selective Catalytic Reduction for 90% control efficiency, or equal, and natural gas auxiliary fuel)	
SO_x	0.054 lb/MMBtu, block 24-hour average (limestone injection for 80% control efficiency, or equal, and natural gas auxiliary fuel)	0.012 lb/MMBtu, block 24-hour average (wet flue gas desulfurization for 95% control efficiency, or equal, and natural gas auxiliary fuel)	
PM_{10}	0.024 lb/MMBtu, 30-minute average (multiclone and electrostatic precipitator, or equal, and natural gas auxiliary fuel)	0.0214 lb/MMBtu, 30-minute average (multiclone and electrostatic precipitator or baghouse, or equal, and natural gas auxiliary fuel)	
CO	0.10 lb/MMBtu, block 24-hour average (good combustion practices and natural gas auxiliary fuel)	0.09 lb/MMBtu, block 24-hour average (oxidation catalyst and natural gas auxiliary fuel)	
VOC	0.01 lb/MMBtu, 30-minute average (good combustion practices and natural gas auxiliary fuel)	0.009 lb/MMBtu, 30-minute average (oxidation catalyst and natural gas auxiliary fuel)	

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 a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required 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 1.3.2

Emission Unit: Biomass-Fired Boiler

Equipment Rating: ≥10 MW

Facility: DTE Stockton, LLC

References: ATC #: N-645-36-0
Project #: N-1101175

Location: 2526 W. Washington St.
Stockton, CA 95203

Date of Determination: TBD

Pollutant	BACT Requirements
NO_x	0.065 lb/MMBtu, block 24-hour average
SO_x	0.054 lb/MMBtu, block 24-hour average
PM_{10}	0.0214 lb/MMBtu, 30-minute average
CO	0.09 lb/MMBtu, block 24-hour average
VOC	0.009 lb/MMBtu, 30-minute average

BACT Status:

X Achieved in practice (SO_x)
___ Small Emitter
X T-BACT (PM_{10})
X Technologically feasible BACT (NO_x, PM_{10}, CO, and VOC)
___ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT
___ Contained in EPA approved SIP
X The following technologically feasible option was not cost effective:
1. SO_x wet scrubber for 95% control efficiency and 0.012 lb/MMBtu

___ Alternate Basic Equipment
___ The following alternate basic equipment was not cost effective:

Appendix E
Health Risk Assessment Summary
and
Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Frank DeMaris, Air Quality Engineer – Permit Services
From:	Glenn Reed, Senior Air Quality Specialist – Technical Services
Date:	November 22, 2010
Facility Name:	POSDEF Power Company
Location:	2526 W Washington St Stockton, CA
Application #(s):	N-645-8-5, -9-5, -10-5, -11-5, -23-4, -36-0, -37-0, -38-0
Project #:	N-1101175

A. RMR SUMMARY

RMR Summary				
Categories	**Stoker-Fired Biomass Boiler (Unit 36-0)**	**Biomass Handling and Storage (Units 37-0 and 38-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	409	0.5	>1.0	>1.0
Acute Hazard Index	0.0	NA[1]	0.0	0.0
Chronic Hazard Index	0.2	NA[1]	0.0	0.0
Maximum Individual Cancer Risk (10^{-6})	8.54[2]	NA[1]	8.54	8.54
T-BACT Required?	**Yes**	**No**		
Special Permit Conditions?	**No**	**No**		

1 Risks for Units 37-0 and 38-0 are included in the risk estimate for Unit 36-0.
2 Risk at the Point of Maximum Impact.

Proposed Permit Conditions

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

Unit # 36-0

No special conditions are required.

Units # 37-0 and 38-0

1. Enforceable conditions should be imposed to ensure that fugitive emissions estimates used for the ambient air quality analysis and RMR are not exceeded.

T-BACT is required for this unit because of emissions of hexavalent chromium which is a PM-10. In accordance with District policy, BACT for this unit will be considered to be T-BACT.

B. RMR REPORT

I. Project Description

Technical Services received a request on July 23, 2010, to perform a Risk Management Review and an Ambient Air Quality Analysis for a proposed modification to a coal-fired power plant. The modification consisted of the installation of: a 699 MMBtu/hr stoker-fired biomass boiler (36-0); a biomass receiving operation (37-0) with two biomass storage piles (11-5 and 23-4); and a biomass fuel handling operation (38-0). Two limestone storage silos (8-5 and 9-5) and one limestone tank (10-5) will be converted to trona. The two coal-fired circulating fluidized bed boilers (14-10 and 15-10) will be decommissioned.

II. Analysis

Toxic emissions for this proposed stoker-fired biomass boiler were calculated using the District's emission factors for biomass power plant emissions from agriculture waste and urban wood waste which are based on approved Toxics Emissions Inventory Report. Fugitive emissions from the biomass handling operations were calculated using a speciation profile from the Air Resources Board (Profile No. 421). In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for this proposed unit was greater than 1.0 (see RMR Summary Table). Therefore, a health risk assessment was necessary.

The following parameters were used for the review:

Analysis Parameters Unit 36-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	45.75	**Closest Receptor (m)**	117.3
Stack Diameter. (m)	3.36	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	14.24	**Max Hours per Year**	8424
Stack Exit Temp. (°K)	450	**Fuel Type**	Wood
Burner Rating (MMBtu/hr)	699		

The biomass receiving operation (i.e., truck unloading) and biomass handling operation at the plant were modeled as area sources with the following parameters:

Analysis Parameters Unit 37-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	22.86	**Closest Receptor (m)**	117.3
Y-Length (m)	33.75	**Type of Receptor**	Business
Release Height (m)	3.00	**Pollutant Type**	PM
		Emission Rate	124 lbs/yr

Analysis Parameters Unit 38-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	21.34	**Closest Receptor (m)**	117.3
Y-Length (m)	20.73	**Type of Receptor**	Business
Release Height (m)	18.30	**Pollutant Type**	PM
		Emission Rate	219 lbs/yr

The disc screening area and the north and west stockpiles were modeled as volume sources with the following parameters:

Analysis Parameters				
Source Type	Volume	**Location Type**		Rural
Emission Rate (hr/day)	See below	**Closest Receptor (m)**		117.3
Emission Rate (hr/year)	See below	**Type of Receptor**		Business
Pollutant Type	Dust			
Units	**Disc Screening**	**North Stockpile**	**West Stockpile**	
Emissions (lbs/yr)	170	272.5	272.5	
Release Height (m)	18.30	9.15	9.15	
Initial Lateral Dimension (m)	4.34	16.88	13.58	
Initial Vertical Dimension m)	8.51	4.26	4.26	

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Biomass Boiler, etc.	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	**X**	Pass	**X**	**X**
NO_x	Pass[1]	**X**	**X**	**X**	Pass
SO_x	Pass	Pass	**X**	Pass	Pass
PM_{10}	**X**	**X**	**X**	Pass[2]	Pass[2]

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The 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 is greater than 1.0 in a million, but less than 10 in a million. **In accordance with the District's Risk Management Policy, the project is approved with Toxic Best Available Control Technology (T-BACT).**

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.

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

Attachments:

A. RMR request from the project engineer
B. Prioritization score
C. Point of Maximum Impact Report
D. Summary of Maximum Air Quality Impacts

San Joaquin Valley Air Pollution Control District
Ambient Air Quality Analysis
Addendum

To:	Frank DeMaris, Air Quality Engineer – Permit Services
From:	Glenn Reed, Senior Air Quality Specialist – Technical Services
Date:	February 23, 2011
Facility Name:	DTE Stockton, LLC
Location:	2526 W Washington St Stockton, CA
Application #(s):	N-645--36-0, -38-0, -39-0
Project #:	N-1101175

Proposed Permit Conditions

To ensure that the particulate emissions from the proposed alternative biomass handling process do not contribute to a violation of the State ambient air quality standards for particulate matter; the following permit conditions must be included for:

Unit # 36-0

No special conditions are required.

Units # 38-0 and 39-0

1. Enforceable conditions should be imposed to ensure that maximum daily and annual fugitive emissions estimates used for the ambient air quality analysis are not exceeded.
2. The following are the fugitive emissions modeled in this analysis:

Unit ID	Modeled Source	Maximum Daily PM10 Emissions (lbs/day)	Maximum Annual PM10 Emissions (lb/yr)
N-645-38-0	Plant Area	0.203	52.90
N-645-39-0	Truck Unloading	0.360	67.27
	Disc Screening	0.554	99.68
	Stockpile Conveyors	0.387	72.17
	Active Stockpile	0.697	202.83
	Inactive Stockpile	0.182	58.83
	Total	2.180	500.79

A. AAQA REPORT

I. Project Description

Technical Services received a request on February 14, 2011 to perform an ambient air quality analysis for an alternate scenario for the biomass receiving, handling, and storage emissions at the DTE Stockton, LLC facility. Previously, DTE had proposed to locate these operations north of the biomass boiler. The alternate scenario locates them to the east of the boiler. The Alternate Scenario will be incorporated into Unit N-645-39-0. Some of the emissions from the Alternate Scenario will also be included as Unit N-645-38-0. Emissions from biomass boiler (Unit N-645-36-0) will be unchanged from those analyzed on November 22, 2011. It was determined that it was not necessary to perform a Risk Management Review for the Alternate Scenario. The cancer risk predicted in the previous analysis was due to emissions of hexavalent chromium and arsenic. Most emissions of those toxic air pollutants are from the boiler and not the biomass handling and storage operations.

II. Analysis

Criteria pollutant emissions from the sources modeled for the Alternate Scenario

The following parameters were used for the analysis:

Analysis Parameters Biomass Boiler Unit 36-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	45.75	**Closest Receptor (m)**	117.3
Stack Diameter. (m)	3.36	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	14.24	**Max Hours per Year**	8424
Stack Exit Temp. (°K)	450	**Fuel Type**	Wood
Burner Rating (MMBtu/hr)	699		

The biomass handling operation at the plant was modeled as an area source with the following parameters:

Analysis Parameters Plant Area Operations Unit 38-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	18.54	**Pollutant Type**	PM
Y-Length (m)	23	**Release Height (m)**	18.3

The Truck Unloading operation was modeled as an area source with the following parameters:

Analysis Parameters Truck Unloading Operation Unit 39-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	40.81	**Pollutant Type**	PM
Y-Length (m)	57.91	**Release Height (m)**	3.1

The disc screening area was modeled as an area source with the following parameters:

Analysis Parameters Disc Screening Area Unit 39-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	12.86	**Pollutant Type**	PM
Y-Length (m)	25	**Release Height (m)**	13.7

Stockpile conveyors were modeled as an area source with the following parameters:

Analysis Parameters Disc Screening Area Unit 39-0			
Source Type	Area	**Location Type**	Rural
X-Length (m)	32.88	**Pollutant Type**	PM
Y-Length (m)	80.33	**Release Height (m)**	9.2

The disc screening area and the north and west stockpiles were modeled as volume sources with the following parameters:

Analysis Parameters				
Source Type	Volume	**Location Type**		Rural
Pollutant Type	PM			
Units	**Active Stockpile**	**Inactive Stockpile**		
Release Height (m)	20.7	7.6		
Initial Lateral Dimension (m)	86.58	38.29		
Initial Vertical Dimension m)	20.7	7.6		

The results from the PM10 Modeling are as follows:

PM10 Modeling Results[1]

Meteorological Year of Data	Maximum 24-Hour Concentration[2]	24-Hour SIL	Maximum Annual Concentration[2]	Annual
2005	3.4867	5.0	0.68174	1.0
2006			0.69336	
2007			0.76448	
2008			0.77758	
2009			0.76088	

1Results are in micrograms per cubic meter.
[2]PM10 concentrations are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS for Particulate Matter as long as the conditions specified at the beginning of this Addendum are included in the Authorities to Construct.

San Joaquin Valley Air Pollution Control District
Risk Management Review
and
Ambient Air Quality Analysis
Addendum 2

To:	Frank DeMaris, Air Quality Engineer – Permit Services
From:	Glenn Reed, Senior Air Quality Specialist – Technical Services
Date:	March 22, 2011
Facility Name:	DTE Stockton, LLC
Location:	2526 W Washington St Stockton, CA
Application #(s):	N-645--36-0
Project #:	N-1101175

A. RMR SUMMARY

RMR Summary				
Categories	**Stoker-Fired Biomass Boiler with Scrubber (Unit 36-0)**	**Biomass Handling and Storage (Units 37-0 and 38-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	409	0.5	>1.0	>1.0
Acute Hazard Index	0.0	NA[1]	0.0	0.0
Chronic Hazard Index	0.2	NA[1]	0.0	0.0
Maximum Individual Cancer Risk (10^{-6})	8.54[2]	NA[1]	8.54	8.54
T-BACT Required?	**Yes**	**No**		
Special Permit Conditions?	**No**	**No**		

1 Risks for Units 37-0 and 38-0 are included in the risk estimate for Unit 36-0.
2 Risk at the Point of Maximum Impact.

Proposed Permit Conditions

To ensure that the emissions from the proposed biomass facility with a wet scrubber do not cause or contribute to a violation of the State or federal ambient air quality standards and do result in a cancer risk to the public greater than 10 in a million; the following permit conditions must be included for:

Unit # 36-0

The emission and source parameters used in this ambient air quality analysis and health risk assessment must be incorporated into the Authority to Construct for this unit.

A. RMR AND AAQA REPORT

I. Project Description

Technical Services received a request on March 17, 2011 to perform a risk management review and ambient air quality analysis for an alternate scenario in which emissions from the stoker fired biomass boiler at the DTE Stockton, LLC facility would be controlled by a scrubber to limit hydrochloric acid emissions. Previously, DTE had proposed to control these emissions with trona injection and an electrostatic precipitator. This Alternate Scenario will be incorporated into Unit N-645-36-0. The major difference between this Alternate Scenario and the original proposal is in the source parameters. The cancer risk predicted in this health risk assessment was due to emissions of hexavalent chromium and arsenic. Most emissions of those toxic air pollutants are from the boiler and not the biomass handling and storage operations.

II. Analysis

Toxic emissions for this proposed stoker-fired biomass boiler were calculated using the District's emission factors for biomass power plant emissions from agriculture waste and urban wood waste which are based on approved Toxics Emissions Inventory Report. Fugitive emissions from the biomass handling operations were calculated using a speciation profile from the Air Resources Board (Profile No. 421). In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for this proposed unit was greater than 1.0 (see RMR Summary Table). Therefore, a health risk assessment was necessary.

The following parameters were used for the analysis:

Analysis Parameters Biomass Boiler with Wet Scrubber Unit 36-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	50.33	**Closest Receptor (m)**	117.3
Stack Diameter. (m)	2.85	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	17.11	**Max Hours per Year**	8424
Stack Exit Temp. (°K)	333	**Fuel Type**	Wood
Burner Rating (MMBtu/hr)	699		

The biomass receiving and handling operations at the plant for this Alternate Scenario do not differ from those in the original proposal.

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM10. The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Biomass Boiler, etc.	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

Concentrations higher than the 24-hour PM10 Significant Impact Level (SIL) were predicted using 2008 meteorological data. These high concentrations were due to emissions from the boiler. A threshold violation file was created to identify all concentrations greater than the SIL were predicted. All exceedances of the SIL occurred on July 5, 2008. The model was run to determine the concentrations for that day from the old plant's emissions. Those concentrations were subtracted from those predicted for the biomass facility to determine if there were any instances where the SIL would be exceeded. There were none.

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk is greater than 1.0 in a million, but less than 10 in a million. **In accordance with the District's Risk Management Policy, the project is approved with Toxic Best Available Control Technology (T-BACT).**

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.

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

Attachments:

A. Point of Maximum Impact Report
B. Summary of Maximum Air Quality Impacts

Attachment B

Summary of Maximum Air Quality Impacts
(µg/m^3)

Pollutant	Averaging Time	Standard	Predicted Concentration	Significant Impact Level	Source Contribution
Respirable Particulate Matter (PM10)	24-Hour	50	129.9	5	<4.99
	Annual Arithmetic Mean	20	27.5	1	0.5
Carbon Monoxide (CO)	8-Hour	10,000	1,939		
	1-Hour	23,000	3,209		
Nitrogen Dioxide (NO_2)	Annual Arithmetic Mean	57	0.78		
	1-Hour	188	155.3		
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	80	26.48		
	24-Hour	105	87.03		
	3-Hour	1,300	203.72		
	1-Hour	196	97.04		

Appendix F
Hazardous Air Pollutant Emissions

DTE ENERGY RESOURCES, INC.
POSDEF PLANT (N-645)
BIOMASS CONVERSION PROJECT -- AUTHORITY TO CONSTRUCT

TOXIC AIR CONTAMINANTS MAXIMUM EMISSIONS - STOKER BOILER

Parameter	
Device	Stoker Boiler
Fuel	Biomass
Steam Generation Rate (lb/hr)	430,000
Max Heat Input Rate (MMBtu/hr)	699
Avg Heat Input Rate (MMBtu/hr)	641
Min Higher Heating Value (Btu/lb)	4,299
Avg Higher Heating Value (Btu/lb)	5,956
Annual Operating Hours	8,424

Pollutant	Emission Factor (lb/ton)	Emission Factor Source	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (lb/yr)	Maximum Annual Emissions (tpy)
Acetaldehyde	1.55E-03	SJVAPCD	1.26E-01	703	3.51E-01
Ammonia (lb/MMBtu)	0.006	DTE	4.2	32,399	16.2
Arsenic	2.32E-06	SJVAPCD	1.89E-04	1.05	5.26E-04
Benzene	1.77E-03	SJVAPCD	1.44E-01	802	4.01E-01
Cadmium	2.54E-05	SJVAPCD	2.06E-03	11.5	5.76E-03
Chromium, Hexavalent	1.85E-06	SJVAPCD	1.50E-04	0.84	4.19E-04
Copper	1.93E-05	SJVAPCD	1.57E-03	8.75	4.37E-03
Dioxins					
Dioxin: 6D 1,2,3,6,7,8	2.18E-11	SJVAPCD	1.77E-09	9.88E-06	4.94E-09
Dioxin: 7D 1,2,3,4,6,7,8	1.23E-10	SJVAPCD	1.00E-08	5.58E-05	2.79E-08
Formaldehyde	1.33E-02	SJVAPCD	1.08E+00	6,029	3.01
Furans					
Furan: 4F 2,3,7,8	1.28E-10	SJVAPCD	1.04E-08	5.80E-05	2.90E-08
Furan: 5F 2,3,4,7,8	7.09E-11	SJVAPCD	5.76E-09	3.21E-05	1.61E-08
Furan: 5F 1,2,3,7,8	4.40E-11	SJVAPCD	3.58E-09	1.99E-05	9.97E-09
Furan: 6F 1,2,3,6,7,8	2.34E-11	SJVAPCD	1.90E-09	1.06E-05	5.30E-09
Furan: 6F 2,3,4,6,7,8	2.74E-11	SJVAPCD	2.23E-09	1.24E-05	6.21E-09
Furan: 6F 1,2,3,4,7,8	2.35E-11	SJVAPCD	1.91E-09	1.07E-05	5.33E-09
Furan: 6F 1,2,3,7,8,9	4.05E-12	SJVAPCD	3.29E-10	1.84E-06	9.18E-10
Furan: 7F 1,2,3,4,6,7,8	3.63E-11	SJVAPCD	2.95E-09	1.65E-05	8.23E-09
Hydrogen Chloride (lb/MMBtu)	0.0037	DTE	2.59	19,979	9.99
Lead	5.54E-05	SJVAPCD	4.50E-03	25	1.26E-02
Manganese	4.99E-03	SJVAPCD	4.06E-01	2,262	1.13E+00
Mercury	2.87E-07	SJVAPCD	2.33E-05	0.13	6.50E-05
PAHs					
Benz(a)anthracene	7.10E-07	SJVAPCD	5.77E-05	0.32	1.61E-04
Benzo(b)fluoranthene	7.59E-08	SJVAPCD	6.17E-06	3.44E-02	1.72E-05
Benzo(k)fluoranthene	3.12E-08	SJVAPCD	2.54E-06	1.41E-02	7.07E-06
Chrysene	9.63E-07	SJVAPCD	7.83E-05	0.44	2.18E-04
Indeno(1,2,3-cd)pyrene	1.73E-08	SJVAPCD	1.41E-06	7.84E-03	3.92E-06
Naphthalene	3.24E-03	SJVAPCD	2.63E-01	1,469	0.73
Toluene	2.93E-04	SJVAPCD	2.38E-02	133	6.64E-02
TOTAL HAPs				31,425	15.7
MAXIMUM HAP				32,399	9.99

Notes

Steam generation rate (in lb/hr), heat input rates (in MMBtu/hr), heating values (in Btu/lb), and operating hours (in hr/day and hr/yr) were obtained from DTE Energy.

Except for NH3 and HCl, emission factors (in lb/ton) were specifed by SJVAPCD for the San Joaquin Solar project. NH3 and HCl emission rates (in lb/MMBtu) were provided by DTE.

Except for NH3 and HCl, hourly emissions (in lb/hr) were calculated from the emission factors (in lb/ton), design heat input rate (in MMBtu/hr), and minumum heating value (in Btu/lb). Hourly NH3 and HCl emissions (in lb/hr) were calculated from the emission rate (in lb/MMBtu) and design heat heat input rate (in MMBtu/hr).

Except for NH3 and HCl, annual emissions (in lb/yr) were calculated from the emission factors (in lb/ton), average heat input rate (in MMBtu/hr), heating value (in Btu/lb), and annual operating hours. Annual NH3 and HCl emissions (in lb/yr) were calculated from the emission rate (in lb/MMBtu), average heat heat input rate (in MMBtu/hr), and annual operating hours.

Ammonia is not a HAP.

Appendix G
QNEC Calculations

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC is calculated as follows:

QNEC = PE2 – BE, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr
BE = Baseline Emissions for each emissions unit, lb/qtr

Using the values in Sections VII.C.2 and VII.D.4 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly}$ = $PE2_{annual}$ ÷ 4 quarters/year
$BE_{quarterly}$ = BE_{annual} ÷ 4 quarters/year

Quarterly Net Emissions Increase (QNEC) (lb/qtr)							
Unit	Pollutant	PE2	BE	Qtr 1	Qtr 2	Qtr 3	Qtr 4
N-645-36-3	NO_X	215,350	0	53,837	53,837	53,838	53,838
	SO_X	139,140	0	34,785	34,785	34,785	34,785
	PM_{10}	107,296	0	26,824	26,824	26,824	26,824
	CO	495,836	0	123,959	123,959	123,959	123,959
	VOC	49,600	0	12,400	12,400	12,400	12,400

Appendix H
Compliance Certification

San Joaquin Valley
Unified Air Pollution Control District

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

[X] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

COMPANY NAME: **POSDEF Power Company, L.P.**	FACILITY ID: **N- 645**
1. Type of Organization:[ ] Corporation [ ] Sole Ownership [ ] Government [X] Partnership [ ] Utility	
2. Owner's Name: **POSDEF Power Company, L.P.**	
3. Agent to the Owner:	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

- Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).
- Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.
- Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.
- Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Signature of Responsible Official

3/17/10
Date

Cynthia A. Tindell
Name of Responsible Official (please print)

Vice President
Title of Responsible Official (please print)

Appendix I
Original POSDEF Offset Evaluation

XI. COMPLIANCE WITH RULE 209.1 (NEW AND MODIFIED STATIONARY SOURCE REVIEW)

A. Best Available Control Technology

1. PM - The particulate matter emissions exceed 150 pounds per day. Therefore, BACT is required.

   a. Fuel Transfer - A total accumulative amount of 2 1/2 gallons of wetting agent solution will be sprayed per ton of coal at the transfer points. In addition all transfer points will be totally enclosed and all belt conveyors will be covered. A control efficiency of at least 95% can be expected. This is considered BACT.

   b. Storage Silos - All storage silos will be totally enclosed and vented only through vent filters. Each vent filter will have a minimum control efficiency of 99.9%. This is considered BACT.

   c. Circulating Fluidized Bed Combustor - The emissions from the combustor will be vented through a baghouse with a control efficiency of greater than 99%. The boiler manufacturer guarantees a total emission rate of 10 lb/hr for both systems. Lowest Achievable Emission Rate not to exceed 10 pounds per hour is considered BACT.

2. SO_x - The SO_x emissions exceed 150 pounds per day. Therefore, BACT is required. Limestone injection into the fluidized bed at a Ca/S molar ratio of 1.6:1 to produce Lowest Achievable Emission Rate is considered BACT.

3. NO_x - The NO_x emissions exceed 150 pounds per day. Therefore, BACT is required. Selective Non-Catalytic Reduction (SNCR) with an ammonia injection rate of 5.5 lb NH_3/lb NO_x to produce Lowest Achievable Emission Rate is considered BACT.

4. CO - The CO emissions exceed 550 pounds per day. Therefore, BACT is required. Automatic adjustment of the combustion air flow to promote effective combustion is considered BACT. The combustion air will be adjusted to an optimum level where NO_x emissions are at the minimum and the CO emissions are at a level which does not cause a significant air quality impact.

5. HC - The hydrocarbon emissions will be less than 150 pounds per day. Therefore, BACT is not required.

B. Offsets

1. PM, SO_x, and NO_x

   The expected emissions from the proposed source exceed the offset thresholds for each of these pollutants. Offsets must be provided to mitigate the worst case net emission increase of 244 lb/day of PM, 625 lb/day of SO_x, and 590 lb/day of NO_x. The applicant has agreed to locate and acquire the needed offsets. The offsets will be actual, annual, quantifiable, and enforceable. Offsets will be provided at appropriate ratios, depending on location, to assure a net benefit in air quality. The applicant will locate the offsets and will submit for the District's approval prior to initiating constructions. The offsets will be cited prior to construction, however, pursuant to District Rule 209.1, the offsets may commence no later than the date of initial start-up of the new source.

2. CO

The CO emissions exceed the District's offset threshold of 550 lbs/day. However, the results of dispersion modeling indicate a nonsignificant CO impact on the existing ambient air quality conditions. Based on modeling, the expected worst case CO impact is well below .5 PPM. A change in ambient air CO concentration of equal to or more than .5 PPM is defined as a significant impact by the District. This value represents the lowest specified measureable concentration by the air quality monitoring instruments operated in San Joaquin County. Therefore, pursuant to the provisions of District Rule 209.1, Part III, Section B.1, the source is exempt from offset requirements for CO.

C. Air Quality Impact

The District Rule requires that emissions from a new source shall not cause or make worse the violation of an ambient air quality standard. The results of the air quality impact modeling, based on unmitigated (i.e., without offsets) emissions from the source are presented in Table XI - C.

The worst case NO_2 or SO_2 impacts, under funigation circumstances, are significant. However, the total impact (i.e., source plus background) in each case will not cause a violation of an air quality standard. The CO and PM impacts are insignificant. The ozone impact could not be modeled because the source is located in an urban area and the District does not have a gridded emission inventory. Furthermore, the source's impact relative to the mobile source emissions from a main freeway near the source was thought to be insignificant. Therefore, it is concluded that no pollutant emissions will make worse an existing violation of an ambient air quality standard nor will cause a new violation. Nevertheless, all criteria pollutant emissions, with the exception of CO and hydrocarbons, will be mitigated at appropriate ratios to assure a net air quality benefit.

Appendix J
Reconstructed Source Analysis

Shaw® Shaw Consultants International, Inc.

A World of **Solutions**

VIA UPS OVERNIGHT

October 25, 2010

Mr. Frank DeMaris
San Joaquin Valley Air Pollution Control District
4800 Enterprise Way
Modesto, CA 95356

RE: POSDEF Power Company, LP – Reconstructed Source Supplemental Information

Mr. DeMaris,

This letter is in response to the SJVAPCD's request for more information on the cost comparison of the POSDEF Power Company, LP facility coal to biomass conversion project to a 50 MW facility to determine if the POSDEF project is considered a "Reconstructed Source" under San Joaquin Air Pollution Control District Rules, Rule 3.32.

Shaw calculated the fixed capital cost to build a new 50 MW facility. Shaw determined the fixed capital cost to be $211,347,000. This was compared to the DTE Conversion estimate (from coal to wood biomass firing) which is $79,089,000. This equates to a conversion versus new cost of 37% well below the Reconstructed Source threshold of 50% (see attached table). Therefore, the facility is not a Reconstructed Source.

Very truly yours,

SHAW CONSULTANTS INTERNATIONAL, INC.

Harry J. Chekos

Harry J. Chekos
Executive Consultant

CC: DTE Energy Resources, Fadi Mourad
Sierra Research, Jeff Adkins

ONE MAIN STREET, SUITE 900 • CAMBRIDGE, MA 02142-1517
617.589.2000 • FAX 617.589.1372

Stockton Biomass - Capital Cost

New Plant vs Conversion

	Total Capital Costs ($000s)		
	Shaw Stockton 50MW	DTE Conversion Estimate	Conversion vs Cost New
Construction Costs			
Material Handling	$8,801	$8,555	
Boiler / AQCS / Steam Turbine / Construction Labor	123,826	41,768	
Engineering/ Home office support	17,602	6,139	
Balance of Plant	35,204	15,223	
Switch Yard	6,601	0	
EPC Contingency/Fee/G&E	19,313	7,405	
Total Construction Costs	**$211,347**	**$79,089**	**37%**

Appendix K
Draft Interpollutant Offset Policy

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

Appendix L
Comments from Center for Biological Diversity and District Response

Comment #1 from Center for Biological Diversity:

First, the Application Review does not provide an explanation for why the District believes the facility can achieve the emissions rate of 0.0037 lbs/MMBtu identified as the relevant emissions factor in calculating the facilities potential to emit ("PTE"). (See App. Rvw., App F.). By the way of comparison, EPA's AP-42 emissions factor for HCl emissions from wood-fired boilers is 0.019 lbs/MMBtu, roughly five times higher than the emission factors used here.

District Response to Comment #1

The EPA emission factor of 0.019 lb-HCL/MMBtu was derived from source test results for biomass-fired stoker boilers that are not equipped with any add-on emission control technologies for reducing hydrogen chloride (HCl) emissions. In contrast, DTE Energy Stockton utilizes a wet scrubber to reduce emissions of HCl; therefore, a much lower emission rate of HCl was anticipated. DTE Energy Stockton's proposed emission factor of 0.0037 lb/MMBtu was based on the emission control guarantees provided by the wet scrubber manufacturer. Furthermore, source testing at the facility has verified that the boiler is operating in compliance with the 0.0037 lbs/MMBtu HCl emission limit. The following table summarizes the results of the source tests performed to date:

Source Test Date	Measured HCl Emissions (lb/MMBtu)
April 18, 2014	0.0020
May 8, 2015	0.002
September 11, 2015	0.001

Comment #2 from Center for Biological Diversity:

Second, even using this relatively low emission factor, the Application Review likely underestimates the facility's PTE for HCl. The Application Review calculated PTE based on the average heat input rate (641 MMBt/hr) and 8,424 hours per year of operation. (App. Rvw. at 6, Appx. F.) However, at the maximum heat input rate (699 MMBtu/hr) and continuous operation (8,760 hours per year), the facility would have the potential to emit 22,656 lbs/yr, or 11.33 tpy, of HCl, which would exceed the major source threshold for HAPs.

This latter calculation, reflecting the maximum capacity of the unit under its physical and operational design, is consistent with the definition of "potential to emit" in both District rules and federal regulations. (District Rule 2201, § 3.27; 40 C.F.R. § 63.2.) In contrast, the operational "assumptions" used in the Application Review to calculate annual PTE—specifically, average heat input rate and hours of operation—are not reflected as enforceable conditions of the permit, and thus cannot be used to reduce the facility's PTE under either District or federal regulations. In calculating PTE, a limitation on a facility's capacity to emit a pollutant, "including . . . *restrictions in hours of operation* or on the *type or amount of material combusted*, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an enforceable permit condition." (District Rule 2201,§ 3.27; see also 40 C.F.R § 63.2 [restrictions on hours of operation or type or amount of material combusted are treated as part of design only if limitation or effect on emissions is "federally enforceable"].) If the District is relying on restrictions on hours of operation or heat input rate in determining PTE, those restrictions must be reflected in the permit as enforceable conditions. The draft ATC conditions here do not contain any such restrictions.

District Response to Comment #2

District Rule 2201, Section 3.2.7 defines Potential to Emit as follows:

> *Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, **including pollution control equipment** and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an enforceable permit condition.*

40 CFR 63.2 defines Potential to Emit as follows:

> *Potential to Emit: means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.*

As both of these definitions indicate, the physical limitations of a control device may be considered when calculating the potential to emit of an emission unit if those limitations are enforceable. The boiler is equipped with a wet scrubber to control HCL emissions. The limit it would have on emissions is made enforceable through Conditions #18 and #19. Condition #19 requires the scrubber to be operated whenever the boiler is in operation, and at or above the average flow rate and PH range as measured during the most recent source test. Condition #18 requires the scrubber to be equipped with a continuous monitoring system that records both the flow rate and PH of the scrubber liquid. The parametric monitoring of the scrubber ensures the measured emission rate from the most recent source test is being met on a continuous basis.

In addition, the permit conditions have been revised to clarify that daily HCL emission calculations are to be based on daily measurements of the boiler's heat input as determined by the CEM, which complies with 40 CFR Part 75 certification requirements. Condition #91 has also been added requiring the source to maintain on site the results of the most recent source test, including the measured HCL emission rate and the applicable scrubber operating parameters.

To provide additional enforceability, the proposed permit limit of 19,980 lb-HCl in any rolling 12-month period has been revised to a rolling daily emission limit. To demonstrate compliance, DTE Energy Stockton will use their CEMs to track the quantity of BTU's consumed daily by the boiler and the emission factor determined from the most recent annual source test for HCl emissions. Compliance with this emission factor is based on monitoring of the scrubber, as discussed above. Using these data, DTE Energy Stockton is able to calculate their rolling annual HCl emissions, on a daily basis.

The District also notes that the source has been operating for more than 2 years under their NSR permit with annual emissions of less than 12,246 lb-HCl/yr, which is significantly lower than the 19,980 lb annual limit. Overall, the use of daily measurement of the heat input rate of the boiler and daily monitoring of the wet scrubber and daily emission calculations rolled on a daily basis are sufficient to limit the potential to emit of the source to less than the HAP major source threshold of 10 tpy for any one pollutant.

Comment #3 from Center for Biological Diversity

Moreover, it does not appear that the PTE calculation for HCl include startup and shutdown emissions. Startup and shutdown emissions were purportedly calculated using the "worst-case potential emissions from combustion of the fuel with highest heating value," specifically 699 MMBtu/hr. (App. Rvw. at 7.) As the calculations in Appendix F clearly demonstrate, however, PTE for HCl was calculated using only the assumed average heat input rate of 641 MMBtu/hr. (App. Rvw., Appx. F [calculating annual PTE of 19,979 lbs/yr, which is the product of 8,424 hours of operation at 641 MMBtu/hr using an emissions factor of .0037 lbs/MMBtu (8,424 * 641 * .0037 = 19,979.2)].)

District Response to Comment #3

The biomass fired boiler uses a wet scrubber to control HCl emissions. The draft ATC includes a requirement for the HCl wet scrubber to be operated at all times whenever the boiler is operated on biomass. Additionally, the final exhaust stack is constructed from fiberglass, so the wet scrubber must be operated in order to cool the exhaust to prevent damage to the fiberglass stack. Since the wet scrubber is operating at all times and the reactions that reduce HCl emissions in the wet scrubber are not known to be temperature dependent, additional HCl emissions are not expected during startup and shutdown of the biomass-fired boiler.

The heat input to the boiler is tracked by the CEMs and is used to keep track of the daily emission rate for HCl. In addition, Condition #50 has been revised to clarify that the annual emission limit includes emissions from startup, shutdown and malfunction periods. Therefore, the assumptions made in calculating the annual HCl emission rate are enforceable.

Comment #4 from Center for Biological Diversity

Furthermore, PTE for HCl was calculated based on 8,424 hours of operation each year, which seems to reflect only "normal operation" and not startup/shutdown operation (See App. Rvw. at 7 [anticipating "8,400 hours of normal operation per year"].) Again, because the facility's calculated PTE is so close to the major source threshold, the Application Review's omission of startup and shutdown emissions from the PTE calculation for HCl undermines its conclusion that the facility is an area source of HAPs.

District Response to Comment #4

First, the District notes that there is no reason to differentiate between startup/shutdown periods and normal operating periods for HCl emissions. During startup, the permit allows the boiler to be fired on natural gas; however, HCl emissions are not expected from the combustion of natural gas. Permit condition #19 requires the wet scrubber to be in operation whenever the boiler is operated on biomass. Therefore, compliance with the permitted HCl emission limit is expected during all periods that the unit is fired on biomass.

As stated earlier, the 19,980 lb/year limit is a federally enforced limit, and the facility keeps records of their HCl emissions on a rolling 365 daily basis to demonstrate compliance using continuous emission monitoring system data and source test data. In addition, Condition #50 has been revised to clarify that the annual emission limit includes emissions from startup, shutdown and malfunction periods.

Comment #5 from Center for Biological Diversity

Third, although the Draft ATC for the biomass boiler contains a condition limiting facility HCl emissions to 19,980 lbs/yr, the related source testing and monitoring conditions are insufficient to ensure practical, enforceable compliance with this limitation. The emissions factor to be used in establishing compliance will be established after the fact through a single source test and annual testing thereafter. (App. Rvw., Appx. A, Draft ATC Permit No. N-645-36-3, Conditions 50, 57.) But these conditions do not specify what steps the facility or the District must take if the actual emissions factor exceeds the factor identified in the application.

Moreover, this facility was permitted with a similar initial source testing condition for HCl more than four years ago. (App. Rvw., Appx. B, ATC N-645-36-0 (June 9, 2011), Conditions 55, 61.) It is not clear from the Application Review whether source tests have been conducted under the existing permit, much less whether those source test data support the emissions factor and PTE calculations set forth here.

District Response to Comment #5

As stated in Comment Response #1 above, the facility has demonstrated compliance with the HCl limit in consecutive source tests. As stated earlier, the current permit includes adequate monitoring, testing, and recordkeeping requirements to ensure compliance in Conditions #18, #19, #50, #57, #71, #85, #89.

In the event that the facility does exceed the rolling 365-day HCl emission limit and becomes a Major Source of HAPs, they will be in violation of their Title V permit and they are required to submit an application to comply with 40 CFR 63 Subpart DDDDD. Permit condition #50 has been modified to read as follows:

> *Condition #50: HCl emissions from this biomass-fired boiler shall not exceed 19,980 pounds in any rolling 365 consecutive day period. HCl emissions shall be calculated daily for comparison to this annual limit using the daily boiler heat input determined pursuant to 40 CFR Part 75, Appendix F, Equation F-15 and the emission factor calculated in the most recent HCl source test. If HCl emissions from the biomass boiler, including emissions from startup, shutdown or malfunction periods are determined to have exceeded 19,999 pounds in any rolling 365-day period, the owner/operator shall submit an Authority to Construct application to comply with 40 CFR 63 Subpart DDDDDD requirements within 30 days of the exceedance. (District Rules 2201 and 4002)*

Comment #6 from Center for Biological Diversity

Finally, although the draft ATC includes conditions requiring monitoring of flow rate and effluent pH in the wet scrubber, these conditions will reveal only whether operations are consistent with flow rate and average pH observed during the most recent source test, not whether the facility is emitting HCl in amounts exceeding the permit limit. (See App. Rvw. at 38; see also Appx. A, Draft ATC Permit No. N-645-36-3, Conditions 18, 19.) As shown in recent comments from U.S. EPA Region 9 concerning a biomass plant in Hawai'i, these conditions should include an enforceable mechanism for calculating actual HCl emissions on a cumulative monthly basis so that compliance with permit limits can be ensured.

District Response to Comment #6

The District notes that the biomass plant in Hawaii that the commenter refers to is not equipped with any HCL control device, whereas the boiler for this project does include a control device which is tested annually and monitored daily to verify the HCL emission rate. It is common for facilities to demonstrate compliance by monitoring surrogate parameters (referred to as parametric monitoring) rather than directly measuring emissions. In the case of a wet scrubber, monitoring of the flow rate ensures that the scrubber liquid is circulating properly. Monitoring of the pH ensures that the scrubber liquor is kept in an ideal state to control emissions. Monitoring of these two parameters ensures that the scrubber is operating properly and is achieving the required emission reductions. Furthermore, although this unit ***is not subject*** to the Boiler MACT (40 CFR 63 Subpart DDDDD), the facility's proposed monitoring conditions ***are identical*** to those required by the Boiler MACT for a biomass-fired boiler with a wet HCl scrubber. A comparison of the Subpart DDDDD requirements and DTE's proposed monitoring requirements is shown in the table below:

40 CFR 63 Subpart DDDDD	**Proposed by Applicant (Boiler is not subject to 40 CFR 63 Subpart DDDDD)**
40 CFR 63 Subpart DDDDD Tables 4 and 7 for HCl Scrubbers without HCL CEMs Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to §63.7530(b) and Table 7 to this subpart. You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.	Draft Authority to Construct Permit Condtion #18. The wet scrubber shall be provided with monitoring equipment that continuously monitors and records the effluent pH and flow rate of the scrubber liquid. [District Rule 2201] Condition #19. The wet scrubber shall be in operation whenever the boiler is operated on biomass. The effluent pH and liquid flow rate, calculated on a rolling 30-day average basis, shall be maintained at or above the average pH and flow rate established during the most recent HCl source test. [District Rules 2201 and 4002]

Since the applicant is monitoring the necessary surrogate parameters to demonstrate compliance and the proposed monitoring scheme is identical to the monitoring required by 40 CFR 63 Subpart DDDDD, the monitoring scheme proposed by the applicant is appropriate for a biomass-fired boiler equipped with an HCl scrubber.

Comment #7 from Center for Biological Diversity

Testing for Toxic Contaminants in Biomass Fuels and Wood Residues Annual testing of a small sample of the facility's fuel is insufficient to ensure compliance with applicable limits on contaminants. The facility will be permitted to use a wide range of fuels, including construction and demolition waste. (App. Rvw. at 40 [defining "biomass"]; Appx. A, Draft ATC Permit No. N-645-36-3, Conditions 27, 28.)

The draft ATC permit for the biomass boiler requires annual testing of a "representative sample," but only once initially and on an annual basis thereafter. (*Id.*, Conditions 59-61) Given the wide variety of fuel types allowed, it is highly unlikely that any single annual test will be truly "representative," much less that it will be performed on the fuels most likely to contain contaminants.

To ensure compliance with applicable regulations, the draft ATC permit should be modified to include (a) requirements for annual tests of basic categories of biomass feedstocks (forest and agricultural products, byproducts, and residues), and (b) testing of all "wood residue" derived from construction and demolition activities.

District Response to Comment #7

The permit allows for a wide variety of fuels because the biomass and wood residue purchased from the suppliers are typically a mixture of the allowed fuels. The facility operates with a target of 60% wood residue and 40% biomass at all times, and the fuel type does not vary considerably. The California Air Toxic Emission Factors (CATEF) emission factors were used to estimate toxic emissions from this plant. The CATEF emission factors are based on biomass-fired plants operating in California that are fired on similar fuels as DTE Stockton, with similar ratios of urban wood waste to biomass.

Furthermore, the facility purchases their fuel from the same suppliers as the other biomass plants operating within the San Joaquin Valley Air Pollution Control District and does not combust painted wood. Therefore, the toxic emissions from DTE Energy Stockton would be similar to other plants operating within the San Joaquin Valley Air Pollution Control District. In fact, DTE Energy Stockton utilizes additional emission control technology, a wet scrubber and oxidation catalyst, which should result in the facility emitting less toxics than the typical biomass plant operating within the San Joaquin Valley Air Pollution Control District.

Since the fuel mix doesn't vary considerably, since the emission factors used to estimate toxic emissions from this plant were based on conservative data, since this plant uses the same fuel supplier as other plants operating within the Air Pollution Control District, and since this plant is utilizing state of the art control technology designed specifically to reduce toxic emissions, the testing requirements are appropriate for this plant.