JUL 2 5 2016

Shamim Reza
Linn Operating, Inc.
5201 Truxtun Ave, Suite 100
Bakersfield, CA 93309

RE: Final - Authority to Construct / Certificate of Conformity (Significant Modification)
Facility Number: S-1246
Project Number: S-1151997

Dear Mr. Reza:

The Air Pollution Control Officer has issued the Authority to Construct permit to Linn Operating, Inc. for the installation of one 5.67 MW cogeneration system, at the Pan Fee Lease in the Heavy Oil Western Stationary Source in Kern County, CA. Enclosed are the Authority to Construct permit and 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 October 12, 2015. The District's analysis of the proposal was also sent to CARB and US EPA Region IX on October 7, 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 a revised top-down Best Available Control Technology (BACT) analysis being performed for gas turbines rated between 3 MW and 10 MW (reference existing BACT guideline 3.4.3). These changes did not trigger additional public notification requirements, nor did they have any impact upon the final BACT 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. Errol Villegas at (559) 230-6000.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:ddb

Enclosures

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

AUTHORITY TO CONSTRUCT

PERMIT NO: S-1246-416-0 **ISSUANCE DATE:** 07/21/2016

LEGAL OWNER OR OPERATOR: LINN OPERATING, INC
MAILING ADDRESS: 5201 TRUXTUN AVE, SUITE 100
BAKERSFIELD, CA 93309

LOCATION: HEAVY OIL WESTERN STATIONARY SOURCE
KERN COUNTY, CA

SECTION: 2 **TOWNSHIP:** 31S **RANGE:** 22E

EQUIPMENT DESCRIPTION:
5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

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. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOx emission reduction credits for the following quantity of emissions: 1st quarter - 3,724 lb, 2nd quarter - 3,724 lb, 3rd quarter - 3,725 lb, and fourth quarter - 3,725 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter - 878 lb, 2nd quarter - 878 lb, 3rd quarter - 878 lb, and fourth quarter - 878 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 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

Arnaud Marjollet, Director of Permit Services

S-1246-416-0 : Jul 21 2016 3:56PM -- BROWND : Joint Inspection NOT Required

5. Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 6,974 lb, 2nd quarter - 6,974 lb, 3rd quarter - 6,974 lb, and fourth quarter - 6,974 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.000 lb-SOx: 1.0 lb-PM10. [District Rule 2201] Federally Enforceable Through Title V Permit

6. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,035 lb, 2nd quarter - 1,035 lb, 3rd quarter - 1,035 lb, and fourth quarter - 1,035 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

7. ERC Certificate Numbers S-4514-2, S-4515-2, S-4516-2, S-4530-2, N-1302-2, N-1332-2, S-4508-5, N-1307-5, N-1309-5, C-1353-5, S-4533-5, S-4539-5, N-1206-4, N-1312-4, S-4510-4, S-4583-4, N-1202-1, N-1295-1, N-1296-1, N-1297-1, S-4500-1, S-4502-1, S-4504-1 (or a certificate split from these certificates) shall be used to supply the required 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. 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

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. 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] Federally Enforceable Through Title V Permit

12. 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]

13. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit

14. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201] Federally Enforceable Through Title V Permit

15. The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330] Federally Enforceable Through Title V Permit

16. During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NOx (as NO2)/startup; 0.053 lb-SOx (as SO2)/startup; 0.423 lb-PM10/startup; 79.3 lb-CO/startup; or 0.5 lb-VOC (as methane)/startup. [District Rule 2201] Federally Enforceable Through Title V Permit

17. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown); 0.024 lb-SOx (as SO2)/shutdown; 0.192 lb-PM10/shutdown; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201] Federally Enforceable Through Title V Permit

18. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320] Federally Enforceable Through Title V Permit

19. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.12 lb/hr or 0.017 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

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

21. The duration of each startup or shutdown shall not exceed 22 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

22. The total duration of startup time shall not exceed either of the following: 44 minutes per day or 132 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit

23. The total duration of shutdown time shall not exceed either of the following: 20 minutes per day or 60 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit

24. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

25. The ammonia slip (NH3) emissions shall not exceed either of the following limits: 0.56 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

26. Annual emissions from the turbine and duct burner system (as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: NOx: 9,932 lb/year (as NO2); SOx: 2,341 lb/year (as SO2); PM10: 18,597 lb/year; CO: 15,121 lb/year; VOC: 2,760 lb/year (as methane); or NH3: 4,922 lb/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201] Federally Enforceable Through Title V Permit

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

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

30. Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4340 and 60.4400] Federally Enforceable Through Title V Permit

31. Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 60 days of startup. [District Rule 2201] Federally Enforceable Through Title V Permit

32. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703] Federally Enforceable Through Title V Permit

33. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081] Federally Enforceable Through Title V Permit

34. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081] Federally Enforceable Through Title V Permit

35. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

36. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400] Federally Enforceable Through Title V Permit

37. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

38. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703] Federally Enforceable Through Title V Permit

39. PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

40. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102] Federally Enforceable Through Title V Permit

41. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703] Federally Enforceable Through Title V Permit

42. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703] Federally Enforceable Through Title V Permit

43. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703] Federally Enforceable Through Title V Permit

44. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

45. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

46. The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

47. If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit

48. The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Federally Enforceable Through Title V Permit

49. The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. If compliance is being demonstrated through fuel sulfur content testing, the testing shall occur at a location after all fuel sources are combined prior to combustion, or by performing mass balance calculations based on testing the sulfur content and volume of each fuel source. [40 CFR 60.4415(a)(1)(i)] Federally Enforceable Through Title V Permit

50. Excess SOx emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)] Federally Enforceable Through Title V Permit

51. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703] Federally Enforceable Through Title V Permit

53. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [40 CFR 60.7] Federally Enforceable Through Title V Permit

54. The permittee shall maintain a record of the cumulative 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201] Federally Enforceable Through Title V Permit

55. The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

56. The owner or operator shall submit a written report of excess emissions and monitoring downtime to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395] Federally Enforceable Through Title V Permit

57. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.7] Federally Enforceable Through Title V Permit

58. All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703] Federally Enforceable Through Title V Permit

San Joaquin Valley Air Pollution Control District

www.valleyair.org

HEALTHY AIR LIVING

Permit Application For:

[ ] ADMINISTRATIVE AMENDMENT [ ] MINOR MODIFICATION [ ] SIGNIFICANT MODIFICATION

1. PERMIT TO BE ISSUED TO:	
2. MAILING ADDRESS: STREET/P.O. BOX: ____________ CITY: ____________ STATE: ____________ 9-DIGIT ZIP CODE: ____________	
3. LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: STREET: ____________ CITY: ____________ ________ ¼ SECTION ________ TOWNSHIP ________ RANGE ________	INSTALLATION DATE:
4. GENERAL NATURE OF BUSINESS:	
5. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary)	
6. TYPE OR PRINT NAME OF APPLICANT:	TITLE OF APPLICANT:
7. SIGNATURE OF APPLICANT: DATE:	PHONE: ( ) FAX: ( ) EMAIL:

For APCD Use Only:

DATE STAMP	*FILING FEE RECEIVED :* $ ____________ *CHECK#:* ____________ *DATE PAID:* ____________ *PROJECT NO:* ____________ *FACILITY ID:* ____________

APPLICATION FOR
TITLE V MODIFICATION

- Instructions -

On the application form, mark the box to indicate what type of Title V modification this is. Only one application form is needed for each facility.

Line 1. Indicate the name of the business exactly as it appears on the Permit to Operate.

Line 2. List the mailing address where correspondence regarding the application and the Permit to Operate may be sent. Please include your nine-digit zip code.

Line 3. List the physical location where the emissions unit(s) will be operated. If a street address is not applicable, provide the United States Geological Survey (USGS) quarter-section, township, and range or the Universal Transverse Mercator (UTM) coordinates. Indicate the installation date of any equipment changes from this modification.

Line 4. Indicate the general nature of the business performed by the facility.

Line 5. Describe each emissions unit. You may reference existing valid District Permits to Operate for each permitted emissions unit. A summary listing of all emissions units with valid District operating permits can be obtained from the District and may be attached and referenced. Reference and attach a copy of the Authority to Construct (ATC) issued by the District for this modification, if one is available.

Line 6. Type or print the name of the applicant followed by the title of the applicant.

Line 7. Sign and date the application in ink. Also include the daytime telephone number, FAX number, and e-mail address of the applicant.

OTHER REQUIRED INFORMATION

Please attach a Title V Modification – Compliance Certification Form (TVFORM-009). If needed to complete the processing of your Title V permit application, the District may request additional information.

APPLICATION FOR TITLE V MODIFICATION

- Instructions -

FEES

A nonrefundable filing fee of $21 per emissions unit, up to a maximum of $1,533 per stationary source, is required. The applicant may submit the necessary filing fees along with this application, or the District will issue a bill for the appropriate fee. Checks or money orders shall be made payable to the SJVUAPCD. All filing fees paid will be credited toward the hourly evaluation fee.

Every applicant for a Title V permit modification, administrative amendment, or certificate of conformity, shall also pay an evaluation fee for the issuance of the Title V permit. The fee shall be calculated using the staff hours expended and a weighted labor rate. All filing fees paid will be credited towards the evaluation fee.

The fee requirements are specified in District Rule 3010 (Permit Fee).

APPLICATION SUBMITTAL

Title V sources are encouraged to schedule a meeting with District personnel prior to submitting Title V applications. Applications, including all supporting documents, must be submitted in duplicate since EPA requires that a copy of each application be forwarded to them. It is recommended that applications be submitted to the Central Regional Office. However, applications may be submitted either by mail or in person at the following locations:

Northern Region Office
(Serving San Joaquin, Stanislaus, and Merced Counties):

4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400
FAX: (209) 557-6475
SBA Hotline: (209) 557-6446

Central Region Office
(Serving Madera, Fresno, and Kings Counties):

1990 E. Gettysburg Avenue
Fresno, California 93726-0244
(559) 230-5900
FAX: (559) 230-6061
SBA Hotline: (559) 230-5888

Southern Region Office
(Serving Tulare and Kern Counties):

34946 Flyover Court
Bakersfield, California 93308
(661) 392-5500
FAX: (661) 392-5585
SBA Hotline: (661) 392-5665

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Cogeneration System Consisting of One Natural Gas-Fired Turbine and Duct Burner

Facility Name:	Linn Operating, Inc	Date:	July 21, 2016
Mailing Address:	5201 Truxtun Ave, Suite 100 Bakersfield, CA 93309	Engineers:	Stanley Tom / Dustin Brown
Contact Person:	Shamim Reza	Lead Engineer	Joven Refuerzo
Telephone:	(661) 616-3889		
E-Mail:	SReza@linnenergy.com		
Application No:	S-1246-416-0		
Project No:	S-1151997		
Deemed Complete:	May 18, 2015		

I. Proposal

Linn Operating, Inc has requested an Authority to Construct (ATC) permit for the installation of one 5.67 MW (ISO rated) combined heat and power cogeneration system consisting of one 67.9 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 57 MMBtu/hr natural gas-fired Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG). The ratings are based upon the higher heating value of natural gas.

The cogeneration operation in this project will be installed at the Pan Fee Lease. The facility has submitted an ATC application for an identical cogeneration operation at the 21Z Lease (Section 21, T30S, R22E). The 21Z Lease is not contiguous or adjacent to the Pan Fee Lease (Section 2, T31S, R22E). Therefore, these two projects are separate Federal stationary sources and can be processed as separate projects.

Linn Operating, Inc. has received their Title V Permit. This modification can be classified as a Title V significant modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). The facility specifically requested that this project be processed in that manner, and the project was sent to Environmental Protection Agency (EPA) for the 45-day comment period on October 7, 2015.

The District received comments from EPA during the 45-day comment period for this project stating that additional NO_X control technologies (e.g. NO_X emissions of 2.0 ppmv @ 15% O_2) may be available for turbines in this size range. Therefore, the District has performed a revised top-down BACT analysis and re-evaluated all feasible control technologies for this class and category of source. The revised top-down BACT analysis is included in Attachment A.

Linn Operating, Inc. must apply to administratively amend their Title V permit prior to operating the proposed equipment authorized under this project.

II. Applicable Rules

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (4/21/11)
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 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 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 Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4703 Stationary Gas Turbines (9/20/07)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
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

The facility is located at the Pan Fee Lease in the Heavy Oil Western Stationary Source, Kern County, CA (Section 2, T31S, R22E). The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The proposed equipment will be used to generate electricity and steam which will be used for facility operations. The combined cycle generator set is equipped with a waste heat recovery steam generator (HRSG).

V. Equipment Listing

Permit #	Equipment Description
S-1246-416-0	5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

VI. Emission Control Technology Evaluation

Emissions from natural gas-fired turbines include NOx, SOx, PM10, CO, and VOC.

NOx is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NOx emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO2 molecule. There are two mechanisms by which NOx is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NOx and prompt NOx), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NOx).

Thermal NOx is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NOx, a form of thermal NOx, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NOx.

Fuel NOx is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N2 in some natural gas, does not contribute significantly to fuel NOx formation. With excess air, the degree of fuel NOx formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NOx, fuel NOx is not currently a major contributor to overall NOx emissions from stationary gas turbines firing natural gas.

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

<u>Selective Catalytic Reduction (SCR)</u>

For control of NOx, the cogeneration unit will utilize selective catalytic reduction (SCR) with anhydrous ammonia injection.

SCR systems selectively reduce NOx emissions by injecting ammonia (NH3) into the exhaust gas stream upstream of a catalyst. NOx, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NOx reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentaoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NOx and NH_3 to pass through the catalyst unreacted.

Oxidation Catalyst (CO Catalyst)

For control of CO, the cogeneration unit will utilize a CO catalyst.

CO emissions result from incomplete combustion, CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, as gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions. CO catalyst is also being used to reduce VOC and organic HAP emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement of introducing reactants. The performance of the oxidation catalyst streams on combustion turbines results in 90+ percent control of CO and above 85 to 90 percent control of formaldehyde. Similar emission reductions are expected for other HAP pollutants.

VII. General Calculations

A. Assumptions

- Operation schedule = 24 hr/day and 365 days/year (per applicant)
- All calculations and physical constants used are corrected to Standard Conditions as defined in District Rule 1020 Section 3.47
- The duct burner is not fired during the turbine startup or shutdown period, but does operate during all other operating modes
- Natural gas higher heating value = 1,000 Btu/scf
- Natural gas F-factor (adjusted to 60 °F) = 8,578 dscf/MMBtu (40 CFR 60 Appendix B)

- Maximum natural gas sulfur concentration = 0.75 gr-S/100 scf (BACT requirement and proposed by the applicant)

The applicant has proposed the following startup and shutdown provisions.

Turbine Startup and Shutdown Daily Events			
Daily # of Startups	Startup Duration (minutes/event)	Daily # of Shutdowns	Shutdown Duration (minutes/event)
2	22	2	10

Turbine Startup and Shutdown Annual Events			
Annual # of Startups	Startup Duration (minutes/event)	Annual # of Shutdowns	Shutdown Duration (minutes/event)
6	22	6	10

B. Emission Factors

<u>Startup</u>

Startup Emissions (22-minute duration)						
Pollutant	NO_X (lb/event)	SO_X (lb/event)	PM_{10} (lb/event)	CO (lb/event)	VOC (lb/event)	NH_3 (lb/event)
Mass Emission Rate	1.6	0.053	0.423	79.3	0.5	0

<u>Shutdown</u>

Shutdown Emissions (10-minute duration)						
Pollutant	NO_X (lb/event)	SO_X (lb/event)	PM_{10} (lb/event)	CO (lb/event)	VOC (lb/event)	NH_3 (lb/event)
Mass Emission Rate	0.4	0.024	0.192	34.7	0.2	0

Steady State

The following emission factors are after the CO catalyst and SCR catalyst based on 100% load.

Turbine + Duct Burner			
Pollutant	ppmvd @ 15% O2	lb/MMBtu	Source
NO_X	2.5	0.00907	BACT Guideline 3.4.3 and Applicant Proposal
SO_X	-	0.00214[1]	BACT Guideline 3.4.3 and Applicant Proposal
PM_{10}	-	0.017	Applicant Proposal
CO	6.0	0.0132	BACT Guideline 3.4.3 and Applicant Proposal
VOC	2.0	0.00252	BACT Guideline 3.4.3 and Applicant Proposal
NH_3	10.0	-	Applicant Proposal

Ammonia (NH_3) from SCR

The proposed daily NH_3 emissions can be calculated as follows:

EF = ppm x MW x 1/379.5 x ff x [20.9 / (20.9 – O_2%)]

Where:

- ppm is the emission concentration in ppmvd @ 3% O_2
- MW is the molecular weight of the pollutant (MW_{NH3} = 17 lb/lb-mol)
- 379.5 is the molar specific volume (lb/MMscf, at 60 °F)
- ff is the F-factor for natural gas/propane (8,578 scf/MMBtu, at 60 °F)
- O_2 is the stack oxygen content to which the emission concentrations are corrected (3%)

EF (lb/MMBtu) = 10 x 17 x 1/379.5 (lb-mol/MMscf) x 8,578 (scf/MMBtu) x [20.9 / (20.9 – 3.0)]
= 0.0045 lb-NH_3/MMBtu

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

(1) Fuel sulfur content limited to 0.75 grains/100 scf. The conversion of this value to lb/MMBtu can be performed using the following calculation: [(0.75 grains/100 scf) * (1 scf/1,000 Btu) * (1 lb/7,000 grains) * (10^6 Btu/MMBtu) * (1 lb-mol SO_X/1 lb-mole S) * (64 lb/1 lb-mol SO_X) * (1 lb-mol S/32 lb)] = 0.00214 lb/MMBtu

2. Post-Project Potential to Emit (PE2)

Startup Emissions

Daily Startup Emissions (22-minutes/event)								
NO_X	1.6	(lb/event)	x	2	(events/day)	=	3.2	(lb/day)
SO_X	0.053	(lb/event)	x	2	(events/day)	=	0.1	(lb/day)
PM_{10}	0.423	(lb/event)	x	2	(events/day)	=	0.8	(lb/day)
CO	79.3	(lb/event)	x	2	(events/day)	=	158.6	(lb/day)
VOC	0.5	(lb/event)	x	2	(events/day)	=	1.0	(lb/day)
NH_3	0	(lb/event)	x	2	(events/day)	=	0.0	(lb/day)

Annual Startup Emissions (22-minutes/event)								
NO_X	1.6	(lb/event)	x	6	(events/year)	=	10	(lb/year)
SO_X	0.053	(lb/event)	x	6	(events/year)	=	0	(lb/year)
PM_{10}	0.423	(lb/event)	x	6	(events/year)	=	3	(lb/year)
CO	79.3	(lb/event)	x	6	(events/year)	=	476	(lb/year)
VOC	0.5	(lb/event)	x	6	(events/year)	=	3	(lb/year)
NH_3	0	(lb/event)	x	6	(events/year)	=	0	(lb/year)

Shutdown Emissions

Daily Shutdown Emissions (10-minutes/event)								
NO_X	0.4	(lb/event)	x	2	(events/day)	=	0.8	(lb/day)
SO_X	0.024	(lb/event)	x	2	(events/day)	=	0.0	(lb/day)
PM_{10}	0.192	(lb/event)	x	2	(events/day)	=	0.4	(lb/day)
CO	34.7	(lb/event)	x	2	(events/day)	=	69.4	(lb/day)
VOC	0.2	(lb/event)	x	2	(events/day)	=	0.4	(lb/day)
NH_3	0	(lb/event)	x	2	(events/day)	=	0.0	(lb/day)

Annual Shutdown Emissions (10-minutes/event)								
NO_X	0.4	(lb/event)	x	6	(events/year)	=	2	(lb/year)
SO_X	0.024	(lb/event)	x	6	(events/year)	=	0	(lb/year)
PM_{10}	0.192	(lb/event)	x	6	(events/year)	=	1	(lb/year)
CO	34.7	(lb/event)	x	6	(events/year)	=	208	(lb/year)
VOC	0.2	(lb/event)	x	6	(events/year)	=	1	(lb/year)
NH_3	0	(lb/event)	x	6	(events/year)	=	0	(lb/year)

Steady State (Turbine 67.9 MMBtu/hr + Duct Burner 57 MMBtu/hr = 124.9 MMBtu/hr)

It will be assumed the turbine will always be run in steady state mode with both the turbine and duct burner at maximum output. The only time the turbine will run without the duct burner is during start up and shut down.

a. Hourly Post-Project Potential to Emit (PE2)

Hourly Steady State Emissions – Turbine + Duct Burner								
NO_X	0.00907	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	1.13	(lb/hour)
SO_X	0.00214	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	0.27	(lb/hour)
PM_{10}	0.017	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	2.12	(lb/hour)
CO	0.0132	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	1.65	(lb/hour)
VOC	0.00252	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	0.31	(lb/hour)
NH_3	0.0045	(lb/MMBtu)	x	124.9	(MMBtu/hr)	=	0.56	(lb/hour)

b. Daily Post-Project Potential to Emit (PE2)

The turbine is assumed to be in startup or shutdown for 64 minutes per day (2 startups/day x 22 min/startup + 2 shutdowns/day x 10 min/shutdown). The emissions from the remaining 1,376 minutes/day (1,440 minutes/day – 64 minutes/day) are calculated in the table below.

Daily Steady State Emissions – Turbine + Duct Burner											
NO_X	0.00907	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	26.0	(lb/day)
SO_X	0.00214	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	6.1	(lb/day)
PM_{10}	0.017	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	48.7	(lb/day)
CO	0.0132	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	37.8	(lb/day)
VOC	0.00252	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	7.2	(lb/day)
NH_3	0.0045	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	1376/60	(hr/day)	=	12.9	(lb/day)

Total Daily Emissions – Turbine + Duct Burner											
	Startup			Shutdown			Steady State			Total	
NO_X	3.2	(lb/day)	+	0.8	(lb/day)	+	26.0	(lb/day)	=	30.0	(lb/day)
SO_X	0.1	(lb/day)	+	0.0	(lb/day)	+	6.1	(lb/day)	=	6.2	(lb/day)
PM_{10}	0.8	(lb/day)	+	0.4	(lb/day)	+	48.7	(lb/day)	=	49.9	(lb/day)
CO	158.6	(lb/day)	+	69.4	(lb/day)	+	37.8	(lb/day)	=	265.8	(lb/day)
VOC	1.0	(lb/day)	+	0.4	(lb/day)	+	7.2	(lb/day)	=	8.6	(lb/day)
NH_3	0.0	(lb/day)	+	0.0	(lb/day)	+	12.9	(lb/day)	=	12.9	(lb/day)

c. Annual Post-Project Potential to Emit (PE2)

The turbine is assumed to be in startup or shutdown for 3.2 hours per year (6 startups/year x 22 min/startup + 6 shutdowns/year x 10 min/shutdown). The emissions from the remaining 8,756.8 hours/year (8,760 hours/year – 3.2 hours/year) are calculated in the table below.

Annual Steady State Emissions – Turbine + Duct Burner											
NO_X	0.00907	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	9,920	(lb/year)
SO_X	0.00214	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	2,341	(lb/year)
PM_{10}	0.017	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	18,593	(lb/year)
CO	0.0132	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	14,437	(lb/year)
VOC	0.00252	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	2,756	(lb/year)
NH_3	0.0045	(lb/MMBtu)	x	124.9	(MMBtu/hr)	x	8,756.8	(hr/year)	=	4,922	(lb/year)

Total Annual Emissions – Turbine + Duct Burner										
	Startup			Shutdown			Steady State			Total	
NO_X	10	(lb/year)	+	2	(lb/year)	+	9,920	(lb/year)	=	9,932	(lb/year)
SO_X	0	(lb/year)	+	0	(lb/year)	+	2,341	(lb/year)	=	2,341	(lb/year)
PM_{10}	3	(lb/year)	+	1	(lb/year)	+	18,593	(lb/year)	=	18,597	(lb/year)
CO	476	(lb/year)	+	208	(lb/year)	+	14,437	(lb/year)	=	15,121	(lb/year)
VOC	3	(lb/year)	+	1	(lb/year)	+	2,756	(lb/year)	=	2,760	(lb/year)
NH_3	0	(lb/year)	+	0	(lb/year)	+	4,922	(lb/year)	=	4,922	(lb/year)

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

Pursuant to 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 values were taken from project S-1144247,

Pre-Project Stationary Source Potential to Emit [SSPE1] (lb/year)							
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC	NH_3
Pre-Project SSPE (SSPE1)	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348	0

Note: $PM_{2.5}$ assumed to be equal to PM_{10}

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

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

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC	NH_3
SSPE1	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348	0
S-1246-416-0	9,932	2,341	18,597	18,597	15,121	2,760	4,922
Post-Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 224,857	> 1,007,094	> 1,086,108	4,922

Note: $PM_{2.5}$ assumed to be equal to PM_{10}

5. Major Source Determination

Rule 2201 Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
Pre-Project SSPE (SSPE1)	> 314,914	> 216,764	> 206,260	> 206,260	> 991,973	> 1,083,348
Post Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 224,857	> 1,007,094	> 1,086,108
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	Yes	Yes	Yes	Yes	Yes	Yes

This source is an existing Major Source and will remain a Major Source.

Rule 2410 Major Source Determination

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)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	> 157.5	> 541.7	> 108.4	> 496.0	> 103.1	> 103.1
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	Y	N	Y	N	N

As shown above, the facility is an existing PSD major source for at least one pollutant.

6. Baseline Emissions (BE)

The BE calculation (in lbs/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, 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 District Rule 2201.

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is a major source, the project's PE2 is compared to the SB 288 Major Modification Thresholds in the following table in order to determine if the SB 288 Major Modification calculation is required.

SB 288 Major Modification Thresholds			
Pollutant	Project PE2 (lb/year)	Threshold (lb/year)	SB 288 Major Modification Calculation Required?
NO_x	9,932	50,000	No
SO_x	2,341	80,000	No
PM_{10}	18,597	30,000	No
VOC	2,760	50,000	No

Since none of the SB 288 Major Modification Thresholds are surpassed with this project, this project does not constitute an SB 288 Major Modification.

8. Federal Major Modification

District Rule 2201 states that major modifications are also federal major modifications, unless they qualify for either a "Less-Than-Significant Emissions Increase" exclusion or a "Plantwide Applicability Limit" (PAL) exclusion.

A Less-Than-Significant Emissions Increase exclusion is for an emissions increase for the project, or a Net Emissions Increase for the project (as defined in 40 CFR 51.165 (a)(2)(ii)(B) through (D), and (F)), that is not significant for a given regulated NSR pollutant, and therefore is not a federal major modification for that pollutant.

- To determine the post-project projected actual emissions from existing units, the provisions of 40 CFR 51.165 (a)(1)(xxviii) shall be used.
- To determine the pre-project baseline actual emissions, the provisions of 40 CFR 51.165 (a)(1)(xxxv)(A) through (D) shall be used.
- If the project is determined not to be a federal major modification pursuant to the provisions of 40 CFR 51.165 (a)(2)(ii)(B), but there is a reasonable possibility that the project may result in a significant emissions increase, the owner or operator shall comply with all of the provisions of 40 CFR 51.165 (a)(6) and (a)(7).
- Emissions increases calculated pursuant to this section are significant if they exceed the significance thresholds specified in the table below.

Significant Threshold (lb/year)	
Pollutant	Threshold (lb/year)
VOC	0
NO_x	0
$PM_{2.5}$	20,000 of direct $PM_{2.5}$ emissions or
	80,000 of sulfur dioxide emissions or
	80,000 of nitrogen oxide emissions
PM_{10}	30,000
SO_x	80,000

The Net Emissions Increases (NEI) for purposes of determination of a "Less-Than-Significant Emissions Increase" exclusion will be calculated below to determine if this project qualifies for such an exclusion.

The facility has submitted an ATC application for an identical cogeneration operation at the Pan Fee Lease (Section 2, T31S, R22E). The Pan Fee Lease is not contiguous or adjacent to the 21Z Lease (Section 21, T30S, R22E). The cogeneration operation in this project will be installed at the 21Z Lease. Therefore, these two projects are separate Federal stationary sources and can be processed as separate projects.

Net Emission Increase for New Units (NEI_N)

Per 40 CFR 51.165 (a)(2)(ii)(D) for new emissions units in this project,

$NEI_N = PE2_N - BAE$

BAE = 0 for the new unit therefore $NEI_N = PE2_N$

Federal Major Modification Net Emissions Increase For New Units (NEI_N)					
Permit	NOx (lb/year)	SOx (lb/year)	PM_{10} (lb/year)	$PM_{2.5}$ (lb/year)	VOC (lb/year)
S-1246-416-0	9,932	2,341	18,597	18,597	2,760

The NEI for this project is thus calculated as follows:

$NEI = NEI_N$

Net Emissions Increase (NEI)					
Permit	NOx (lb/year)	SOx (lb/year)	PM_{10} (lb/year)	$PM_{2.5}$ (lb/year)	VOC (lb/year)
S-1246-416-0	9,932	2,341	18,597	18,597	2,760

Federal Major Modification Threshold			
Pollutant	NEI (lb/year)	Threshold (lb/year)	Federal Major Modification?
NO_X	9,932	0	Yes
SO_X	2,341	80,000	No
PM_{10}	18,597	30,000	No
$PM_{2.5}$	18,597	20,000 of direct $PM_{2.5}$ emissions	No
	3,117	80,000 of sulfur dioxide emissions	No
	9,932	80,000 of nitrogen oxide emissions	No
VOC	2,760	0	Yes

The NEI for this project will be greater than the federal Major Modification threshold for NOx and VOC. Therefore, this project does not qualify for a "Less-Than-Significant Emissions Increase" exclusion and is thus determined to be a Federal Major Modification for NOx and VOC.

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

Rule 2410 applies to pollutants for which the District is in attainment or for unclasssified, pollutants. The pollutants addressed in the PSD applicability determination are listed as follows:

- NO_2 (as a primary pollutant)
- SO_2 (as a primary pollutant)
- CO
- PM
- PM_{10}

I. Project Location Relative to Class 1 Area

As demonstrated in the "PSD Major Source Determination" Section above, the facility was determined to be a existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

II. Potential to Emit for New or Modified Emission Units vs PSD Major Source Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the total potentials to emit from all new and modified units are below the applicable thresholds, no futher PSD analysis is needed.

PSD Major Source Determination: Potential to Emit (tons/year)					
	NO_2	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	5.0	1.2	7.6	9.3	9.3
PSD Major Source Thresholds	40	40	100	25	15
New PSD Major Source ? (Y/N)	N	N	N	N	N

As demonstrated above, because the post-project total potentials to emit from all new and modified emission units are below the PSD significant emission increase thresholds, this project is not subject to the requirements of Rule 2410 and no further discussion is required.

10. Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Quarterly NEC [QNEC]			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	2,483	0	2,483
SO_X	585	0	585
PM_{10}	4,649	0	4,649
CO	3,780	0	3,780
VOC	690	0	690

VIII. Compliance

Rule 1080 Stack Monitoring

This rule specifies that specific source types be equipped with CEMs. The proposed emission unit is not one of the listed source types. Additionally, this rule specifies performance, data reduction, recordkeeping, and reporting criteria for continuous emissions monitors.

Since the turbine will not be equipped with CEMS, the provisions of this rule are not applicable to this project.

Rule 1081 Source Sampling

This rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The following conditions will be listed on the permit to ensure compliance:

- The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]
- The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District approval 15 days prior to such testing. [District Rule 1081]
- Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]

Therefore, compliance with the requirements of this rule is expected.

Rule 1100 Equipment Breakdown

This rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified. The following conditions will be listed on the permit to ensure compliance:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]
- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Therefore, compliance with the requirements of this rule is expected.

Rule 2201 New and Modified Stationary Source Review Rule

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. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

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

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

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

As seen in Section VII.C.2 above, the applicant is proposing to install a new natural gas-fired turbine with heat recovery with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lbs/day. However BACT is not triggered for NH_3 as ammonia emissions are intrinsic to the operation of the selective catalytic reduction (SCR) system, which is BACT for NOx emissions. Emissions from a control device that is determined by the District to be BACT are not subject to BACT.

Natural Gas-Fired Turbine with Heat Recovery		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	26.0	Yes
SO_x	6.2	Yes
PM_{10}	48.7	Yes
CO	37.8	Yes
VOC	7.2	Yes
NH_3	12.9	No*

* BACT is not triggered for NH_3 since emissions from a control device that is determined to be BACT is not subject to BACT.

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

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

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

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Section VII.C.7 and VII.C.8 above, this project does constitute a Federal Major Modification for NOx and VOC. Therefore BACT is triggered for NOx and VOC for all emission units in the project for which there is an emission increase.

2. BACT Guideline

BACT Guideline 3.4.3 applies to the natural gas-fired turbine in this project. [Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)] (See Attachment A)

3. Top-Down BACT Analysis

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

Pursuant to the attached Top-Down BACT Analysis (see Attachment A), BACT has been satisfied with the following:

NO_X: 2.5 ppmvd @ 15% O2, based on a three hour average (selective catalytic reduction)
SO_X: PUC-regulated natural gas or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf

PM_{10}: Air inlet cooler, lube oil vent coalescer, and natural gas fuel
CO: 6.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal)
VOC: 2.0 ppmvd @ 15% O2, based on a three-hour average (catalytic oxidation)

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post-Project SSPE (SSPE2)	> 324,846	> 219,105	> 224,857	> 1,007,094	> 1,086,108
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	Yes	Yes	Yes	Yes

2. Quantity of Offsets Required

As seen above, the facility is an existing Major Source for all pollutants and the SSPE2 is greater than the offset thresholds; therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio

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)

There are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

Offsets Required (lb/year) = (Σ[PE2 – BE]) x DOR

<u>CO Offset Calculations</u>

CO offsets are triggered by CO emissions in excess of 200,000 lb/year for the facility.

However, pursuant to Section 4.6.1, "Emission Offsets shall not be required for the following: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards (AAQS)."

The Technical Services Section of the San Joaquin Valley Unified Air Pollution Control District performed a CO modeling run, using the EPA AERMOD air dispersion model, to determine if the CO emissions would exceed the State and Federal AAQS. Modeling of the worst case 1 hour and 8 hour CO impacts were performed. These values were added to the worst case ambient concentration (background) measured and compared to the ambient air quality standards.

This modeling demonstrates that the proposed increase in CO emissions will not cause a violation of the CO ambient air quality standards. Therefore, the increase in CO emissions is exempt from offsets pursuant to Section 6.4.1.

Offset Requirement				
Pollutant	NOx (lb/year)	SOx (lb/year)	PM_{10} (lb/year)	VOC (lb/year)
PE2	9,932	2,341	18,597	2,760
BE	0	0	0	0
PE2 – BE	9,932	2,341	18,597	2,760

The project is a Federal Major Modification for NO_X and VOC emissions and therefore subject to a distance offset ratio of 1.5:1. In addition, a preliminary review of the proposed PM_{10} and SO_X emission reduction credits to be used for the porposed of this project shows that the location of those original reductions is more than 15 miles from the proposed equipment site. Therefore, PM_{10} and SO_X are subject to a distance offset ratio of 1.5:1.

Assuming an offset ratio of 1.5:1, the amount of ERCs that need to be withdrawn for this project are as follows:

Offset Requirement x DOR (1.5)				
Pollutant	NOx (lb/year)	SOx (lb/year)	PM_{10} (lb/year)	VOC (lb/year)
PE2	14,898	3,512	27,896	4,140
BE	0	0	0	0
PE2 – BE	14,898	3,512	27,896	4,140

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

Quarterly Offset Requirement x DOR (1.5)				
Pollutant	1st Qtr (lb/qtr)	2nd Qtr (lb/qtr)	3rd Qtr (lb/qtr)	4th Qtr (lb/qtr)
NOx	3,724	3,724	3,725	3,725
SOx	878	878	878	878
PM_{10}	6,974	6,974	6,974	6,974
VOC	1,035	1,035	1,035	1,035

The applicant has stated that the facility plans to use the following ERC certificates to offset the increases in emissions associated with this project. The certificates have available quarterly credits as follows:

Proposed NOx ERC Certificates				
ERC Certificate #	1st Qtr (lb/qtr)	2nd Qtr (lb/qtr)	3rd Qtr (lb/qtr)	4th Qtr (lb/qtr)
S-4514-2	4,332	1,450	4,332	1,569
S-4515-2	11,433	0	0	0
S-4516-2	239	239	239	239
S-4530-2	0	0	5,400	1,920
N-1302-2	0	0	2,915	0
N-1332-2	0	400	0	4,000
Total	16,004	2,089	12,886	7,728

Proposed SOx ERC Certificates				
ERC Certificate #	1st Qtr (lb/qtr)	2nd Qtr (lb/qtr)	3rd Qtr (lb/qtr)	4th Qtr (lb/qtr)
S-4508-5	4,606	5,021	4,825	6,146
N-1307-5	0	0	749	0
N-1309-5	749	0	0	693
C-1353-5	0	807	0	0
S-4533-5	342	284	342	398
S-4539-5	929	929	929	929
Total	6,626	7,041	6,845	8,166

Proposed PM_{10} ERC Certificates				
ERC Certificate #	1st Qtr (lb/qtr)	2nd Qtr (lb/qtr)	3rd Qtr (lb/qtr)	4th Qtr (lb/qtr)
N-1206-4	0	6,024	9,030	2,588
N-1312-4	0	1,322	662	3,304
S-4510-4	0	0	0	508
S-4583-4	0	0	0	14,000
Total	0	7,346	9,692	20,400

Proposed VOC ERC Certificates				
ERC Certificate #	1st Qtr (lb/qtr)	2nd Qtr (lb/qtr)	3rd Qtr (lb/qtr)	4th Qtr (lb/qtr)
N-1202-1	66	66	66	66
N-1295-1	157	144	137	134
N-1296-1	0	0	20	0
N-1297-1	0	1,027	0	0
S-4500-1	8	1,433	8	8
S-4502-1	1,307	1,307	1,307	1,308
S-4504-1	284	0	0	0
Total	1,822	3,977	1,538	1,516

The applicant proposes to use SO_X for PM_{10} offsets. The District has established an interpollutant offset ratio (IOR) of 1.000:1 per draft Interpollutant Offset Ratio Policy (reference Policy APR 1430).

As seen above, the facility has sufficient credits to fully offset the quarterly emissions increases associated with this project.

Proposed Rule 2201 (offset) Conditions

- Prior to operating equipment under this Authority to Construct, permittee shall surrender NOx emission reduction credits for the following quantity of emissions: 1st quarter – 3,724 lb, 2nd quarter – 3,724 lb, 3rd quarter – 3,725 lb, and 4th quarter – 3,725 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]
- Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter – 878 lb, 2nd quarter – 878 lb, 3rd quarter – 878 lb, and 4th quarter – 878 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]
- Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter – 6,974 lb, 2nd quarter – 6,974 lb, 3rd quarter – 6,974 lb, and 4th quarter – 6,974 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.000 lb-SOx: 1.0 lb-PM10. [District Rule 2201]
- Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter – 1,035 lb, 2nd quarter – 1,035 lb, 3rd quarter – 1,035 lb, and 4th quarter – 1,035 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201]
- ERC Certificate Numbers S-4514-2, S-4515-2, S-4516-2, S-4530-2, N-1302-2, N-1332-2, S-4508-5, N-1307-5, N-1309-5, C-1353-5, S-4533-5, S-4539-5, N-1206-4, N-1312-4, S-4510-4, S-4583-4, N-1202-1, N-1295-1, N-1296-1, N-1297-1, S-4500-1, S-4502-1, S-4504-1 (or a certificate split from these certificates) shall be used to supply the required 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 Notification

1. Applicability

Public noticing is required for:
a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification.

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in VII.C.7 and VII.C.8, this project does constitute a Federal Major Modification for NOx and VOC emissions; therefore, public noticing for Federal Major Modification purposes is required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	30.0	100 lb/day	No
SO_X	6.2	100 lb/day	No
PM_{10}	49.9	100 lb/day	No
CO	265.8	100 lb/day	Yes
VOC	8.6	100 lb/day	No
NH_3	12.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The following table compares pollutant will trigger public noticing requirements. As seen the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	> 314,914	> 324,846	20,000 lb/year	No
SO_X	> 216,764	> 219,105	54,750 lb/year	No
PM_{10}	> 206,260	> 224,857	29,200 lb/year	No
CO	> 991,973	> 1,007,094	200,000 lb/year	No
VOC	> 1,083,348	> 1,086,108	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	Project PE2 (lb/year)	Project PE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_X	9,932	0	9,932	20,000 lb/year	No
SO_X	2,341	0	2,341	20,000 lb/year	No
PM_{10}	18,597	0	18,597	20,000 lb/year	No
CO	15,121	0	15,121	20,000 lb/year	No
VOC	2,760	0	2,760	20,000 lb/year	No
NH_3	4,922	0	4,922	20,000 lb/year	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

e. Title V Significant Permit Modification

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V Significant Modification. Therefore, public noticing for Title V Significant Modification is required for this project.

2. Public Notice Action

As discussed above, public noticing is required for this project for Federal Major Modification for NOx and VOC emissions, CO emissions in excess of 100 lb/day, and Title V Significant Permit Modification. Therefore, public notice documents will be submitted to the US Environmental Protection Agency (US EPA), 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 permit for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions

- During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NOx (as NO2)/startup; 0.053 lb-SOx (as SO2)/startup; 0.423 lb-PM10/startup; 79.3 lb-CO/startup; or 0.5 lb-VOC(as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2)/shutdown; 0.024 lb-SOx (as SO2)/shutdown; 0.192 lb-PM10/startup; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201]
- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.12 lb/hr or 0.017 lb/MMBtu. [District Rule 2201]
- The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330]
- The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 0.56 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is required to demonstrate compliance with Rule 2201.

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201. Source testing will be required within 60 days of initial start-up.

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4400(a)]
- Performance testing to measure the PM10 emissions (lb/hr).shall be conducted within 60 days of startup. [District Rule 2201]
- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]
- VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
- PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
- Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]

2. Monitoring

The following conditions will be listed on the permit to ensure compliance with the assumptions made for Rule 2201.

- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]

- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
- If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

- Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following conditions will be listed on the permit to ensure compliance:

- The permittee shall maintain a record of the cumulative 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]
- The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]
- The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]
- All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

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 Attachment D of this document for the AAQA summary sheet.

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

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 Section VIII above, this facility is a new major source and this project does constitute a Title I modification, therefore this requirement is applicable. The facility's compliance certification is included in Attachment B.

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to install a cogeneration operation.

Since the project will provide power to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

Rule 2410 Prevention of Significant Deterioration

The prevention of significant deterioration (PSD) program is a construction permitting program for new major stationary sources and major modifications to existing major stationary sources located in areas classified as attainment or in areas that are unclassifiable for any criteria air pollutant.

As demonstrated above, this project is not subject to the requirements of Rule 2410 due to a significant emission increase and no further discussion is required.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a "permit amendment that does not qualify as a minor permit modification or administrative amendment."

Section 3.20.5 states that a minor permit modification is a permit modification that does not meet the definition of modification as given in Section 111 or Section 112 of the Federal Clean Air Act. Since this project is a Title I modification (i.e. Federal Major Modification), the proposed project is considered to be a modification under the Federal Clean Air Act. As a result, the proposed project constitutes a Significant Modification to the Title V Permit pursuant to Section 3.29.

As discussed above, the facility has applied for a Certificate of Conformity (COC) (see Attachment C); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The facility shall not implement the changes requested until the final permit is issued.

Rule 2540 Acid Rain Program

Pursuant to CFR 40 Section 72.7, the acid rain program standards apply to any new utility that serves one or more generators with a total nameplate capacity of 25 MWe or more and burns only fuel with a sulfur content of 0.05 percent or less by weight. The nameplate rating for the proposed unit is 5.67 MWe. Thus, this unit is not subject to the Part 72 Acid Rain Program requirements and an application for an acid rain permit is not required.

Rule 4001 New Source Performance Standards (NSPS)

<u>40 CFR 60 – Subpart GG – Standards of Performance for Stationary Gas Turbines</u>

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. The proposed turbine is new. Therefore, the proposed turbine meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. The proposed turbine is new. Therefore, the proposed turbine also meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to the proposed turbine. Therefore, the turbine is exempt from the requirements of 40 CFR 60 Subpart GG.

40 CFR 60 – Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60 Subpart KKKK applies to all stationary combustion turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbine involved in this project has a rating of 67.9 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to the gas turbine.

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

Section 60.4320 - Standards for Nitrogen Oxides

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

The facility is proposing a NO_X emission concentration limit of 2.5 ppmvd @ 15% O_2 for the turbine. Therefore, the proposed turbine will be operating in compliance with the NO_X emission requirements of this subpart. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 60.4330 - Standards for Sulfur Dioxide

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

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

The facility is proposing to burn natural gas fuel in the turbine with a maximum sulfur content of 0.75 grain/100 scf (0.00214 lb/MMBtu). Therefore, the proposed system will be operating in compliance with the SO_X emission requirements of this section. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330]

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

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

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

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

The turbine does not utilize water or steam injection. Therefore, the requirements of this section are not applicable to this project.

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

Paragraph (a) states if you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with Section 60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, you must resume annual performance tests.

Paragraph (b) states as an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems: (1) Continuous emission monitoring as described in Sections 60.4335(b) and 60.4345, or (2) Continuous parameter monitoring as follows: (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously. (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode. (iii) For any turbine that uses SCR to reduce NOx emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls. (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOx emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

The following condition will be listed on the permits to ensure compliance with the requirements of this section:

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340]

Section 60.4345 – CEMS Equipment Requirements

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

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

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

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

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

The facility will not install and operate a NO_X CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

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

Section 60.4350 states that for purposes of identifying excess emissions:

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

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

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

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).
(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

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

The facility will not install and operate a NO_X CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

Section 60.4355 – Parameter Monitoring Plan

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions.

As discussed above, the facility is proposing to perform annual source testing. Therefore, the requirements of this section are not applicable.

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

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

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

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

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

Linn Operating is proposing to operate these turbines on natural gas that has a maximum sulfur content of 0.75 grains/100 scf. Depending on the source of the natural gas used in these units, the facility may be able to demonstrate compliance by providing a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates that the natural gas sulfur content is less than or equal to 0.75 grains/100 scf. If that option cannot be met, Linn Operating will be required to physically monitor the sulfur content be incorporated into their permit.

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

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

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

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

Linn Operating is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every calendar quarter. If any quarterly monitoring period shows an exceedance, weekly monitoring shall resume. Linn Operating is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for these turbines. The following condition will ensure continued compliance with the requirements of this section:

- The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios.

As discussed above, the facility is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

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

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

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

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

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls.

The facility is not proposing to use CEMs or monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this section are not applicable.

Section 60.4385 – Excess SO_X Emissions

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

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.
(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

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

- Excess SO_X emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SO_X begins when a sample is not taken by its due date. A period of monitor downtime for SO_X also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO_X monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

Sections 60.4375 and 60.4395 – Reporting

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

- The owner or operator shall submit a written report of excess emissions and monitoring downtime to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395]

Section 60.4400 – NO_X Performance Testing

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

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

The facility will be required to source test the exhaust of this turbine within 60 days of initial startup and at least once every 12 months thereafter. The facility will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]
- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]

Section 60.4405 – Initial CEMS Relative Accuracy Testing

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d).

The facility will not install and operate a NOx CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

Section 60.4410 – Parameter Monitoring Ranges

Section 60.4410 sets forth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls.

As discussed above, the facility is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable.

Section 60.4415 – SO_X Performance Testing

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

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

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

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

Linn Operating is proposing to periodically determine the sulfur content of the fuel combusted in each of these units when valid purchase contracts, tariff sheets or transportation contract that show the sulfur content is less than 0.75 grains/100 scf are not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. If compliance is being demonstrated through fuel sulfur content testing, the testing shall occur at a location after all fuel sources are combined prior to combustion, or by performing mass balance calculations based on testing the sulfur content and volume of each fuel source. [40 CFR 60.4415(a)(1)(i)]

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

Conclusion

Conditions will be incorporated into the permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected.

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

40 CFR 63 – Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Section 63.6080 states Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

Section 63.6085 states you are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

This stationary source has the potential to emit of any single HAP less than 10 tons per year and combination of HAPs less than 25 tons per year. Therefore, the requirements of this subpart are not applicable to this project.

Rule 4101 Visible Emissions

Rule 4101 states that 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.

The following condition will be listed on the permit 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]

Rule 4102 Nuisance

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

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Attachment D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.
The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-1246-416-0	0.0024 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Attachment D of this report, the emissions increases for this project was determined to be less than significant.

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

Particulate matter calculations were performed for each piece of equipment by the following equation:

F-Factor for natural gas:	8,578 dscf/MMBtu
PM_{10} Emission Factor:	0.017 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust:	100%

$$GL = \left(\frac{0.017\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu}\right)$$

$$GL = 0.014\ grain/dscf < 0.1\ grain/dscf$$

Since the particulate matter concentration is ≤ 0.1 grains per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the permit to ensure compliance:

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

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr.

Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the proposed equipment.

Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter. As shown below, the unit's maximum hourly emission rates are below the Rule 4301 limits.

District Rule 4301 Limits			
Unit	NO_2	Total PM	SO_2
S-1246-416-0	1.25	2.08	0.27
Rule 4301 Limit	140 lb/hr	10 lb/hr	200 lb/hr

As shown above, compliance with this rule is expected.

Rule 4305 Boilers, Steam Generators, and Process Heaters (Phase 2)

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4305 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4305 are not applicable to the duct burner.

Rule 4306 Boilers, Steam Generators, and Process Heaters (Phase 3)

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4306 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4306 are not applicable to the duct burner.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4320 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4320 are not applicable to the duct burner.

Rule 4703 Stationary Gas Turbines

Rule 4703 limits NOx and CO emissions from stationary gas turbines with ratings of greater than 0.3 megawatts and/or maximum heat input ratings of more than 3,000,000 Btu/hr. The facility proposes to install one 5.67 MW gas turbine, therefore this rule applies.

Section 5.1 – NOx Emission Requirements

Sections 5.1.1 and 5.1.2 specify the Tier 1 and Tier 2 NO_X compliance limits. As discussed below, Linn Operating is proposing to operate this turbine in compliance with the Tier 3 NO_X emission limits specified in section 5.1.3. The Tier 3 NO_X emission limits are more stringent than the Tier 1 and Tier 2 NO_X emission limits. Therefore, compliance with the Tier 1 and Tier 2 NO_X emission limits will be demonstrated with compliance of the Tier 3 NO_X emission limits and no further discussion is required.

Section 5.1.3 (Tier 3) of this rule limits the NO_X emissions from natural gas fired stationary gas turbine systems rated between 3 MW to 10 MW and allowed to operation for more than 877 hours per year to 5 ppmv @ 15% O_2. As discussed above, the proposed turbine will be limited to 2.5 ppmv @ 15% O_2, therefore compliance with this section is expected. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 5.2 – CO Emission Requirements

Per Table 5-4 of section 5.2, the CO emissions concentration from the proposed turbine must be less than 200 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

The facility is proposing a CO emission concentration limit of 6.0 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbine will be operating the turbine in compliance with the CO emission requirements of this rule. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 5.3 – Startup and Shutdown Requirements

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

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

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

- During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NOx (as NO2)/startup; 0.053 lb-SOx (as SO2)/startup; 0.423 lb-PM10/startup; 9.3 lb-CO/startup; or 0.5 lb-VOC (as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2)/shutdown; 0.024 lb-SOx (as SO2)/shutdown; 0.192 lb-PM10/startup; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201]
- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]
- The duration of each startup or shutdown shall not exceed 22 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 – Monitoring and Record Keeping

Section 6.2.1 requires the owner or operator to either install, operate, and maintain continuous emissions monitoring equipment for NOx and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring. The applicant has proposed to determine a relation between the ammonia injection rate and the NOx emissions rate. The applicant will then monitor the ammonia injection rate to the SCR system to determine NOx compliance. To factor in degradation of the SCR catalyst, the applicant will be required to periodically monitor the NOx and O2 emissions rates using a portable analyzer. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703]
- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]

- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
- If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. The proposed turbine will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbine was not in operation prior to August 18, 1994 and the requirements of this section are not applicable.

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

- 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 1070, 2201, and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. The facility will not install and operate a NOx CEMS. Therefore, the requirements of this section are not applicable to this project.

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

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. The proposed turbine is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable.

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

Sections 6.3 and 6.4 – Compliance Testing

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

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbine will be allowed to operate greater than 877 hours per year. Therefore, the requirements of this section are not applicable.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

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

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

The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]

- The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703]
- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703]

Conclusion

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected.

Rule 4801 Sulfur Compounds

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

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume } SO_2 = \frac{n\,RT}{P}$$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\frac{10.73\,\text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

0.75 gr-S/100 scf:

$$\frac{0.00214\,lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\,dscf} \times \frac{1\,lb \cdot mol}{64\,lb} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.48\frac{parts}{million}$$

$SulfurConcentration = 1.48\frac{parts}{million}$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California 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 proposed project is located in Kern County and is thus, subject to the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting.* The *Kern County Zoning Ordinance* was developed by the Kern County Planning Agency as a comprehensive set of goals, objectives, policies, and standards to guide development, expansion, and operation of oil and gas exploration within Kern County. In 2015, Kern County revised their *Kern County Zoning Ordinance* in regards to exploration, drilling and production of hydrocarbon resources projects. The revised Kern County Zoning Ordinance establishes a written process (Conformity Review permit process or Minor Activity permit) by which oil and gas exploration projects involving site-specific operations can be evaluated to determine whether the environmental effects of the operation were covered in the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting* Environmental Impact Report (EIR). For this project, Kern County also adopted an Addendum to the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting Environmental Impact Report* (State Clearinghouse No. 2013081079) on July 14, 2016.

As a responsible agency the District complies with CEQA by considering the EIR prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project involved (CCR §15096). The District has reviewed the EIR and the addendum prepared by the Lead Agency for the project and finds them to be adequate. To reduce project related impacts on air quality, the District requires air pollutant emission controls on the project as required by Best Available Control Technology (BACT) under District Rule 2201 (New and Modified Stationary Source Review). In addition, the District is requiring the applicant to surrender emission reduction credits (ERC) for stationary source emissions above the offset threshold. For stationary source emissions that are below the offset threshold, i.e. not required to surrender ERCs, and for non-stationary source emissions, Kern County will enter into an Oil and Gas Emission Reduction Agreement (OG-ERA) with the District. Pursuant to the OG-ERA, the applicant shall pay fees or reduce emissions from other sources to fully offset project emissions that are not required to be offset by District permit rules and regulations.

Thus, the District finds that through a combination of project design elements, compliance with applicable District rules and regulations, and compliance with District air permit conditions, project specific stationary source emissions will have a less than significant impact on air quality. Pursuant to CCR §15096, prior to project approval and issuance of ATCs the District will prepare findings. Upon project approval the District will file a Notice of Determination with Kern County.

Indemnification Agreement and Letter of Credit

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 proposed project has a Stationary Source Increase in Potential to Emit (SSIPE) greater than the District's CEQA significance thresholds; however, it has been determined to have a less than significant environmental impact with mitigation (under the District's New Source Review Rule, the applicant is required to provide offsets in the form of emission reduction credits to mitigate air quality impacts). The proposed project is also a potential operation of public concern in the Valley (Oil and Gas), triggers Best Available Control Technology (BACT), and triggers public notice. As such, the District has determined that an Indemnification Agreement is required.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authority to Construct permit S-1246-416-0 subject to the permit conditions on the attached draft Authority to Construct permits in Attachment E.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-1246-416-0	3020-8A-D	5.67 MW	$3,062

Attachments

A: Revised Top Down BACT Analysis for Gas Turbines with Heat Recovery, Rated between 3 MW and 10 MW
B: Statewide Compliance Certification
C: Certificate of Conformity
D: Health Risk Assessment and Ambient Air Quality Analysis
E: Draft Authority to Construct Permit
F: EPA Comments and District Responses

Attachment A

Revised Top Down BACT Analysis for Gas Turbines with Heat Recovery, Rated between 3 MW and 10 MW

San Joaquin Valley Air Pollution Control District

Revised BACT Determination for Guideline 3.4.3

Gas Turbine with Heat Recovery (≥ 3 MW and ≤ 10 MW)

Facility Name:	Linn Operating, Inc.	Date:	July 15, 2016
Mailing Address:	5201 Truxton Ave, Suite 1000	Engineer:	Dustin Brown
	Bakersfield, CA 93309	Lead Engineer:	Jerry Sandhu
Contact Person:	Shamim Reza		
Telephone:	(661) 616-3889		
E-Mail:	SReza@linnenergy.com		
Project #:	S-1151996		
Application #:	S-1246-415-0		

I. PROPOSAL

Linn Operating, Inc. has requested an Authority to Construct (ATC) permit for the installation of one 5.67 MW (ISO rated) combined heat and power cogeneration system consisting of one 67.9 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 57 MMBtu/hr natural gas-fired Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG).

Current Best Available Control Technology (BACT) guideline 3.4.3 is applicable to the proposed 5.67 MW combined heat and power cogeneration system. For NO_X emissions, current BACT guideline 3.4.3 requires achieved in practice as 2.5 ppmvd NO_X @ 15% O_2 and does not list any technologically feasible or alternate basic equipment control options. However, the District received comments from the Environmental Protection Agency (EPA) during the public notice period for this project stating that additional NO_X control technologies (e.g. NO_X emissions of 2.0 ppmv @ 15% O_2) may be available for turbines in this size range. Therefore, the District has agreed to perform a revised top-down BACT analysis and re-evaluate all feasible control technologies for this class and category of source.

II. PROJECT LOCATION

Linn Operating's facility is located at the 21Z Lease in the Heavy Oil Western Stationary Source in Kern County, CA (Section 21, T30S, R22E).

III. EQUIPMENT LISTING

S-1246-415-0:

5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

IV. PROCESS DESCRIPTION

The proposed equipment will consist of a 5.67 MW (ISO rated) combined heat and power generation system consisting of one 67.9 MMBtu/hr natural gas-fired turbine and one 57 MMBtu/hr natural gas fired duct burner. The combined cycle generator set is also equipped with a waste heat recovery steam generator (HRSG). The electricity and steam generated by the proposed system will be used onsite for facility operations.

V. CONTROL EQUIPMENT EVALUATION

The proposed gas turbine will be equipped with emission control equipment for NO_X, CO and VOC. NO_X is controlled utilizing a selective catalytic reduction (SCR) system, and CO and VOC will be controlled utilizing an oxidation catalyst.

Selective Catalytic Reduction (SCR)

For control of NO_X emissions, the cogeneration unit will utilize selective catalytic reduction (SCR) with anhydrous ammonia injection.

SCR systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentaoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 ^oF. Exhaust gas temperatures greater than the upper limit (750 ^oF) will cause NO_X and NH_3 to pass through the catalyst unreacted.

The use of an SCR system will reduce NO_X emissions from Linn Energy's cogeneration system to 2.5 ppmvd @ 15% O_2 (based on three-hour average). The proposed maximum ammonia slip (NH_3) concentrations in the exhaust during operation will be 10 ppmvd @ 15% O_2.

Oxidation Catalyst (CO Catalyst)

For control of CO and VOC emissions, the cogeneration unit will utilize a CO catalyst.

CO emissions result from incomplete combustion when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, as gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement of introducing reactants. The use of an oxidation catalyst will reduce CO emissions from Linn Operating's cogeneration system to 6 ppmvd @ 15% O_2, based on a three-hour average.

VOC emissions also result from incomplete combustion of fuel in the turbine. The proposed oxidation catalyst converts unburned hydrocarbons into CO_2 and water (H_2O) via the following reaction:

$$2C_xH_y + (2x + y/2)O_2 \rightarrow 2xCO_2 + yH_2O$$

The use of an oxidation catalyst will reduce VOC emissions from Linn Operating's cogeneration system to 2 ppmvd @ 15% O_2, based on a three-hour average.

A. Best Available Control Technology (BACT) for Permit Unit S-1246-415-0:

Applicability

District Rule 2201 Section 4.1 states that BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following:

a) Any new emissions unit with a potential to emit exceeding two pounds per day,
b) The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day, and/or
c) Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day.
d) When a Major Modification is triggered for a modification project at a facility that is a Major Source.

Section 4.2 states that BACT is not triggered for CO emissions if the facility's post project Stationary Source Potential to Emit (SSPE2) is less than 200,000 lb of CO per year. The SSPE2 for this facility is greater than 200,000 lb of CO per year; therefore, BACT can be triggered for CO emissions from emission units located at this facility.

PE Table	NO_X (lb/day)	SO_X (lb/day)	PM_{10} (lb/day)	CO (lb/day)	VOC (lb/day)
S-1246-415-0	26.0	6.2	48.7	37.8	7.2
BACT Triggered?	Yes	Yes	Yes	Yes	Yes

As shown above, BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC emissions from the proposed heat and power cogeneration system.

B. BACT Policy

Per District Policy APR 1305, 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 following steps may be simply cited from the Clearinghouse without further analysis."

Current Best Available Control Technology (BACT) guideline 3.4.3 (see Appendix II) is applicable to the proposed 5.67 MW combined heat and power cogeneration system. However, the District received comments from EPA Region IX on November 12, 2015 stating that additional NO_X control technologies (e.g. NO_X emissions of 2.0 ppmv @ 15% O_2) may be commercially available for turbines in this size range. Therefore, the District has agreed to perform a revised top-down BACT analysis for NO_X emissions and evaluate all feasible control technologies for this class and category of source. In addition, even though specific comments were only received regarding potential NO_X control technologies available for turbines in this size range, the District will also complete a revised top down BACT analysis for SO_X, PM_{10}, CO, and VOC emissions. Therefore, this revised BACT determination will address BACT for each of these five pollutants from Linn Operating's proposal and will include a full update to BACT Guideline 3.4.3 in the District's BACT clearinghouse.

C. Top-Down BACT Analysis

I. NO_X Emissions:

a. Step 1 - Identify All Possible Control Technologies

The following references were consulted to determine the level of control that is currently being required.

California Air Resources Board (CARB) BACT Clearinghouse
EPA BACT/LAER Clearinghouse
South Coast Air Quality Management District (SCAQMD) BACT Clearinghouse
Bay Area Air Quality Management District (BAAQMD) BACT Clearinghouse
San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse

The following Rules were also consulted:

SJVAPCD Rule 4703 (Stationary Gas Turbines)
SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines)
BAAQMD Regulation 9, Rule 9 (Nitrogen Oxides from Stationary Gas Turbines)
40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)

BACT Clearinghouse Survey:

District/ AQMD	Guideline or Application Number	Achieved-in-Practice	Technologically Feasible
SJVAPCD	3.4.3	2.5 ppmv @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal)	N/A
SCAQMD	BACT Guidelines – Part D: Gas Turbine	2.5 ppmvd @ 15% O_2 (most stringent limit, can allow higher NO_X limits if turbine efficiency is greater than 34%)	N/A
BAAQMD	89.1.5	5.0 ppm, dry @ 15% O_2	2.5 ppmv, dry @ 15% O_2 (achieved in practice for > 12 MW)
CARB	Application Number 2012-APP-002100 (4.37 MW unit from a San Diego BACT analysis)	5 ppmvd @ 15 O_2, 1 hour average	N/A
CARB	Application Number 2012-APP-002049 (4.6 MW unit from a San Diego BACT analysis)	9 ppmvd @ 15 O_2, 1 hour average	N/A
CARB	Application Number 358625 (9.9 MW unit from a South Coast BACT analysis)	25 ppmvd @ 15 O_2	N/A
EPA	RBLC ID PA-0289 (55.62 MMBtu/hr heat and power combustion turbine)	15 ppm @ 15% O_2	N/A
EPA	RBLC ID CA-1216 (4.6 MW turbine with duct burner – Grossmont Hospital)	9 ppm @ 15% O_2	N/A
EPA	RBLC ID CT-0155 (2.4 MW cogeneration facility)	0.1800 g/bhp-hr (approximately 13 – 15 ppm @ 15% O_2 based on turbine efficiency of 30 – 35%)	N/A
EPA	RBLC ID FL-0313 (62.70 MMBtu/hr cogen system turbine #2 with duct burner)	25 ppm @ 15% O_2	N/A

Applicable Rules Survey:

District/AQMD	Rule	NO_X Limit
SJVAPCD	4703	5 ppmv @ 15% O_2 (3 MW to 10 MW units allowed to operate ≥ 877 hour/year)
SCAQMD	1134	9 ppmv @ 15% O_2 (2.9 to less than 10 MW, worst case turbine eff. of 25%)
BAAQMD	Reg 9, Rule 9	25 ppmv @ 15 % O_2 (50 – 150 MMBtu/hr, with controls available)
EPA	Subpart KKKK	25 ppmv @ 15 % O_2 (50 – 850 MMBtu/hr, natural gas firing)

List of Other Control Options Found:

California Air Resources Board Guidance for the Permitting of Electrical Generation Technologies

The CARB document recommends that for stationary combined cycle gas turbines rated between 3-12 MW, the NO_X BACT standard be set 0.12 lb/MW-hr (2.5 ppmvd @ 15% O_2).

Environmental Protection Agency (EPA) Comments on District Project S-1151996

On November 12, 2015, the District received a comment from the Environmental Protection Agency that they believed gas turbines in this size range can achieve NO_X emission levels down to 2 ppm @ 15% O_2, averaged over a three-hour period. Therefore, the District will consider this control option as a part of this revised BACT determination.

District Findings During Revised BACT Determination

During the achieved in practice analysis for this revised BACT determination, the District has determined that NO_X emissions of 2.25 ppmv @ 15% O_2 could also be a potential control option for turbines in this class and category of operation. Therefore, the District will consider this control option as a part of this revised BACT determination.

Achieved-in-Practice Determination:

Achieved in practice (AIP) shall be an emission level or an emission control technology or technique that has been identified by the District, CARB, EPA, or any other air pollution control District as having been AIP for the same class and category of source. An emission control technology or technique is considered to be AIP provided all of the following are satisfied:

- At least one vendor must offer this equipment for regular or full-scale operation. A performance guarantee should be (but is not required to be) available with the purchase of the control technology.

- The control technology must have been installed and operated reliably at one or more commercial facilities for at least 180 days.

- The control technology must be verified to perform effectively over the range of operation expected for that class and category of source. The verification shall be based on a performance test or tests, when possible, or other performance data.

2.0 ppmv @ 15% O_2 and 2.25 ppm @ 15% O_2:

Existing SJVAPCD BACT guideline 3.4.3 lists AIP NO_X as 2.5 ppmv @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal). The District currently has four turbines permitted in this size range operating with a NO_X emission limit of 2.5 ppm @ 15% O_2. A summary of the equipment authorized by these permits is shown in the table below:

Permit	Equipment	Installation Date
S-39-56	5.24 MW cogeneration system including 73.0 MMBtu/hr Solar Tauraus model 60 natural gas fired turbine engine with SoloNOx combustors, selective catalytic reduction (SCR), 47.2 MMBtu/hr duct burner system, heat recovery hot oil heater and oxidation catalyst	8/12/2009
S-318-16	3.5 MW nominally rated Solar model C40S-4701 natural gas-fired turbine cogeneration unit with dry low NO_X combustor, selective catalytic reduction (SCR), an oxidation catalyst, and unfired heat recovery steam generator (HRSG)	11/11/2008
S-6534-3	5.432 MW electric power generation system (combined cycle configuration) consisting of a 67.1 MMBtu/hr Solar model TAURUS 65-8401S natural gas-fired combustion turbine with a 106.4 MMBtu/hr duct burner, all served by a CO catalyst and a selective catalytic reduction (SCR) system with ammonia injection	12/2/2008
S-6534-5	5.67 MW electric power generation system (combined cycle configuration) consisting of a 67.65 MMBtu/hr Solar model TAURUS60-7901S natural gas-fired combustion turbine with a 106.4 MMBtu/hr natural gas/biogas-fired duct burner, all served by a CO catalyst and a Rentech selective catalytic reduction (SCR) system with ammonia injection	9/22/2014

For each of the turbines referenced above, a source test for NO_X emissions has been performed at least once every twelve months since the time of installation. A summary of each unit's NO_X source test results are shown in the tables below:

S-39-56:

Test Date	Run 1 (ppm @ 15% O_2)	Run 2 (ppm @ 15% O_2)	Run 3 (ppm @ 15% O_2)	Average (ppm @ 15% O_2)
10/3/2014	2.03	1.93	1.91	1.96
11/1/2013	1.93	1.93	1.89	1.92
10/31/2012	1.82	1.91	1.90	1.88
11/1/2011	1.92	2.05	2.04	2.00
10/5/2010	2.11	2.10	2.08	2.10
10/8/2009	1.30	1.11	1.14	1.18

S-318-16:

Test Date	Run 1 (ppm @ 15% O_2)	Run 2 (ppm @ 15% O_2)	Run 3 (ppm @ 15% O_2)	Average (ppm @ 15% O_2)
9/3/2014	1.8	1.9	2.2	2.0
9/4/2013[(1)] (ppm @ 15% O_2)	2.4	2.3	2.2	2.3
9/4/2013[(1)] (ppm by volume)	1.9	1.8	1.7	1.8
9/11/2012	2.5	2.5	2.4	2.5
9/20/2011	2.0	1.9	1.7	1.9
9/30/2010	1.5	2.0	2.0	1.9
4/13/2009	1.0	0.9	0.8	0.9

S-6534-3:

Test Date	Run 1 (ppm @ 15% O_2)	Run 2 (ppm @ 15% O_2)	Run 3 (ppm @ 15% O_2)	Average (ppm @ 15% O_2)
10/9/2015	2.18	2.45	2.35	2.33
9/23/2014	1.78	1.24	1.24	1.42
9/4/2013[(2)]	N/A	N/A	N/A	1.54
9/5/2012	0.57	1.01	1.08	0.89
9/8/2011	1.65	1.60	1.42	1.56
10/5/2010	1.87	1.89	1.70	1.82
9/9/2009	1.30	1.40	1.25	1.32

[(1)] The results for this particular source test only reference the NO_X ppm values by volume and did not list the NO_X ppm values corrected to 15% O_2. The NO_X ppm values corrected to 15% O_2 were estimated by comparing other year's source test results conversion from NO_X ppm volume dry to NO_X ppm at 15% O2 and applying the lowest conversion factor to the results from this source test. The 2014 and 2012 source tests showed an average conversion factor of 1.25. Therefore, the NO_X ppm values corrected to 15% O_2 were estimated by multiplying the NO_X ppm values by volume by 1.25.
[(2)] Individual source test run data not available for the 2013 source test. Run data included in the final source test report was the run data performed for the previous source test conducted in 2012.

S-6534-5:

Test Date	Run 1 (ppm @ 15% O_2)	Run 2 (ppm @ 15% O_2)	Run 3 (ppm @ 15% O_2)	Average (ppm @ 15% O_2)
9/29/2015	0.34	0.97	1.68	1.42
9/24/2014	1.29	1.08	1.72	1.36

The District has reviewed the source tests that have been performed on each of these turbines. Even though not all of the source tests show that turbines were meeting a NO_X emissions limit of 2.0 ppmv, @ 15% O_2, it has been shown that turbines in this size range are capable of meeting a NO_X emission level of less than or equal to 2.0 ppm @ 15% O_2.

However, pursuant to information provided by Linn Operating as a part of this project, NO_X emissions from turbines in this class and category of source can vary depending on turbine load and other operating conditions (e.g. fuel quality, elevation, humidity, ambient temperatures, etc.). In accordance with Solar's Dry Low Emissions Technology publication (see Appendix III), Figure 3, the outlet NO_X emissions from the proposed turbine can vary by as much as 7 ppm over the target operating range that the proposed turbine is planned to operate across. Assuming the SCR system achieves 90% control for NO_X emissions, this could potentially result in as much as a 0.7 ppm difference in the exhaust stack NO_X emission rate from the proposed turbine. Based on the source test data referenced above, that variation in the outlet NO_X ppm value could result in one of these turbines failing a required NO_X emission limit of 2.0 ppmv @ 15% O_2 or 2.25 ppmv @ 15% O_2.

Lastly, the SCR system catalyst degrades over time and needs to be replaced (typically once every five years). The combustion systems in the turbine and HSRG duct burner can also degrade over time (between major overhauls). Degradation of these systems can also result in higher NO_X emissions over time. And although unit S-6534-5 has had two consecutive years with source tests below 2.0 ppm @ 15% O_2; as can be seen with the other units that have been installed for a longer period of time, NO_X emissions are expected to gradually increase over time due to the degradation of the combustion and catalyst systems.

These potential NO_X emission variances during turbine and emission control system operation require cogen equipment suppliers such as Solar Turbines to maintain a reasonable margin of compliance within their emission limit guarantees for the NO_X levels that operators may experience under their typical operating conditions. Information in the facility files of the original permitting projects for each of the four turbines/control systems referenced above shows that the manufacturer only guaranteed a NO_X emissions rate of 2.5 ppmv @ 15%.

Conclusion:

As discussed above, a control option is considered to be AIP provided all three of the following parameters are satisfied:

1) At least one vendor must offer this equipment for regular or full-scale operation. A performance guarantee should be (but is not required to be) available with the purchase of the control technology; and
2) The control technology must have been installed and operated reliably at one or more commercial facilities for at least 180 days; and
3) The control technology must be verified to perform effectively over the range of operation expected for that class and category of source. The verification shall be based on a performance test or tests, when possible, or other performance data.

Based on information obtained as a part of this top down BACT analysis, with proper design, Solar Turbines in conjunction with Rentech Boiler Systems and Haldor Topsoe can offer a turbine system that falls within this class and category of source that would be guaranteed to achieve NO_X emissions of 2.0 ppmv @ 15% O_2 over the entire range of its required operation.

Each of the four turbines referenced above have been installed and operated for more than 180 days. Source test results have shown that the units have the ability to meet a NO_X emission limit of 2.0 ppmv @ 15% O_2 at the time the source test was performed. However, the source test reports do not document turbine load or other operating conditions when the source test data was collected and the District does not have data readily available on what the NO_X emissions are from these turbines during other times of the year. Therefore, a sufficient demonstration has not been made that these turbines are capable of meeting a NO_X emission level of 2.0 ppmv @ 15% O_2 or 2.25 ppmv @ 15% O_2, over all ranges of their required operation, and on a consistent, long-term basis.

In addition, the District did not find any other turbines or regulatory requirements that demonstrated small turbines in this size range are currently required or consistently capable of achieving NO_X emissions of less than or equal to 2.0 ppmv @ 15% O_2 or 2.25 ppmv @ 15% O_2.

Therefore, it cannot be shown that this control operation meets items 2 and 3 as described above and these control options are not being considered AIP for turbines in this class and category of source at this time.

2.5 ppmv @ 15% O_2:

The next most stringent NO_X emission limit remaining from the control options identified above is 2.5 ppm @ 15% O_2, which is already set as the AIP BACT option from existing SJVAPCD guideline 3.4.3. In addition, the District already has four permitted turbines complying with this NO_X BACT requirement and Linn Operating is proposing to operate the proposed turbine with a selective catalytic reduction system and NO_X emissions of less than or equal to 2.5 ppmv @ 15% O_2. Therefore, the AIP BACT level for NO_X emissions will be set equal to the following:

1. 2.5 ppmv @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal)

Technologically Feasible Control Alternatives:

2.0 ppmv @ 15% O_2:

Pursuant to information provided by Linn Operating as a part of this project, the turbine system could be re-designed with SoLoNOx combustors and a larger catalyst section within the SCR system to potentially achieve NO_X emissions down to 2.0 ppmv @ 15% O_2 on a regular basis. Therefore, the District has determined that this control option is Technologically Feasible for this class and category of operation and it will be considered as a part of this BACT determination.

2.25 ppmv @ 15% O_2:

Pursuant to information provided by Linn Operating as a part of this project, the turbine system could be re-designed with SoLoNOx combustors and a larger catalyst section within the SCR system to potentially achieve NO_X emissions down to 2.25 ppmv @ 15% O_2 on a regular basis. Therefore, the District has determined that this control option is Technologically Feasible for this class and category of operation and it will be considered as a part of this BACT determination.

b. Step 2 – Eliminate Technologically Infeasible Options

Both control options identified in step 1 above have been determined to be technologically feasible.

c. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	2.0 ppmv @ 15% O_2 (selective catalytic reduction or equal)	No
2	2.25 ppmv @ 15% O_2 (selective catalytic reduction or equal)	No
3	2.5 ppmv @ 15% O_2 (selective catalytic reduction or equal)	Yes

d. Step 4 – Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options that have not been determined to be achieved in practice in the list from Step 3 above, in the order of their ranking, to determine the cost effective option with the lowest emissions.

District BACT Policy APR 1305 establishes annual cost thresholds for imposed control based upon the amount of pollutants reduced by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is \$24,500 per ton of NO_X emissions reduced.

For the purposes of District cost effectiveness analysis, the amount of emissions reduced is defined as the emissions from the technologically feasible control option versus District Standard Emissions (DSE) from this class and category of operation. For new emission units, DSE are equal to the emissions level allowed by an applicable District rule once the final compliance date for the rule has passed. As discussed in this analysis above, District Rule 4703 requires small turbines rated between 3 MW and 10 MW to operate with emissions of 5 ppmvd @ 15% O_2 or less. Therefore, DSE for the purposes of this top-down BACT analysis will be set equal to 5 ppmv @ 15% O_2.

<u>**Option 1 - 2.0 ppmv @ 15% O_2:**</u>

On February 1, 2016 and February 26, 2016, Linn Operating provided estimates on the total costs of bringing NO_X emissions from a DSE rate of 5 ppmv @ 15% O_2 to 2.0 ppmv @ 15% O_2 for their proposed 5.67 MW turbine system. The cost data was supplied to Linn Energy by the key vendors that are providing the proposed turbine system equipment being installed in this proposed project and include, but are not limited to, Solar Turbines, Rentech Boiler Systems and Haldor Topsoe.

The original cost estimates provided for this project included costs associated with installing and maintaining a continuous emission monitoring (CEM) system. However, the District does not feel it is necessary for a CEM system to be installed to reduce the NO_X emissions from 5 ppm to 2 ppm @ 15% O_2. Therefore, the costs associated with the CEM system have been removed from the original cost estimates provided.

In addition, the District is using the lowest cost estimate provided by Linn Energy for each item needed to reduce the NO_X emissions from 5 pppm to 2 ppm @ 15% O_2. Therefore, the most conservative cost numbers are being used for the purposes of this cost effectiveness analysis.

<u>A. Capital Cost</u>

The capital cost included the following items:

- SoLoNOx combustors for gas turbine - \$300,000
- Modifications to heat recovery steam generator (HRSG) (larger SCR section, lower NO_X duct burners, installation space for more catalyst) - \$150,000
- Increased amount of SCR catalyst required – \$100,000

- Increased tank and system capacities for higher aqueous ammonia volumes used in SCR process - $125,000
- Increased construction costs (HSRG foundation and erection, ammonia tank and system erection, SCR/catalyst installation) - $67,500

The total capital cost was estimated as follows:

Total Capital Cost: $742,500

Pursuant to the District BACT Policy, Section X, the annual cost of installing and maintaining the SCR system will be calculated as follows. The installation cost will be spread over the expected life of the SCR system which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: $A = [P * I(I+1)^n]/[(I+1)^n-1]$

Where:
A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$A = [\$742,500 * 0.1 * (1.1)^{10}]/[(1.1)^{10}-1]$
= $121,028/year

B. Operation and Maintenance Costs

The operation and maintenance costs included the following items:

- Increased turbine fuel usage due to increased back pressure from additional catalyst - $21,024
- Increase in grid power purchases due to reduced cogen power output, from increased turbine back pressure – $48,180
- Increase electrical demand on system due to increased size of SCR system, larger aqueous ammonia vaporizer, and transfer fans – $12,527
- Increased consumable costs such as SCR catalyst material, labor/equipment to replace catalyst, and increased ammonia usage - $93,250

The total operation and maintenance cost was estimated as follows:

Estimated Operation and Maintenance Cost: $174,981/year

C. Total Annual Cost

Annualized Cost = Annualized Capital Cost + Annual Op and Maint Costs
Annualized Cost = \$121,028/year + \$174,981/year

Annualized Cost$_{2.0 \text{ ppmv NOx @ 15\% O2}}$ = \$296,009/year

D. NO_X Emission Reductions

The NO_X emissions can be converted from ppmv to lb/MMBtu using the following equation:

EF = ppm x MW x 1/379.5 x off x [20.9 / (20.9 – O_2%)]

Where:

- ppm is the emission concentration in ppmvd @ 15% O_2
- MW is the molecular weight of the pollutant (MW_{NOX} = 46 lb/lb-mol)
- 379.5 is the molar specific volume (lb/MMscf, at 60 °F)
- ff is the F-factor for natural gas/propane (8,578 scf/MMBtu, at 60 °F)
- O_2 is the stack oxygen content to which the emission concentrations are corrected (15%)

DSE Option - 5.0 ppmv @ 15% O_2:

EF (lb/MMBtu) = 5.0E-6 x 46 x 1/379.5 (lb-mol/MMscf) x 8,578 (scf/MMBtu) x [20.9 / (20.9 – 15)]
= 0.0184 lb-NO_X/MMBtu

Technologically Feasible Option - 2.0 ppmv @ 15% O_2:

EF (lb/MMBtu) = 2.0E-6 x 46 x 1/379.5 (lb-mol/MMscf) x 8,578 (scf/MMBtu) x [20.9 / (20.9 – 15)]
= 0.0074 lb-NO_X/MMBtu

Using the total burner rating of the turbine and the duct burner proposed in this project (124.9 MMBtu/hr), the emission reductions generated by installing control equipment capable of achieving NO_X emissions of 2.0 ppm @ 15% O_2 are as follows:

NO_X Reductions = (DSE NO_X EF – Tech Feasible NO_X EF) x 124.9 MMBtu/hr x 8,760 hr/year
NO_X Reductions = (0.0184 lb/MMBtu – 0.0074 lb/MMBtu) x 124.9 MMBtu/hr x 8,760 hr/year

NO_X Reductions = 12,035 lb/year

E. Cost of NO_X Emission Reduction

Cost of reductions = (\$296,009/yr)/(12,035 lb/yr)(1 ton/2000 lb)
= **\$49,191/ton of NO_X reduced**

The cost of reducing NO_X emissions to 2.0 ppmv @ 15% O_2 would be greater than the \$24,500/ton cost effectiveness threshold of the District BACT policy. This control option is therefore not cost effective and is being removed from consideration at this time.

Option 2 - 2.25 ppmv @ 15% O_2:

A. Total Annual Cost

Linn Operating did not provide specific cost information on the equipment and/or controls necessary to bring the NO_X emissions from a DSE rate of 5 ppmv @ 15% O_2 to 2.25 ppmv @ 15% O_2 for their proposed 5.67 MW turbine system. However, pursuant to information provided by Linn Operating for this project, the additional equipment and controls needed to reduce the NO_X emissions down to 2.25 ppm @ 15% O_2 is identical to the equipment and/or controls necessary to achieve NO_X emissions of 2.0 ppmv @ 15% O_2, as described in Option 1 above. Therefore, the total annual cost to achieve NO_X emissions of 2.25 ppmv @ 15% O_2 should be \$296,009 per year.

However, as an ultra conservative estimate for the purposes of this revised BACT analysis, the total annual cost to bring the NO_X emissions down to 2.25 ppmv @ 15% O_2 will be estimated at 50% of the cost of achieving NO_X emissions of 2.0 ppmv @ 15% O_2.

Annualized Cost = \$296,009/year * 50%

Annualized $\text{Cost}_{2.25\ \text{ppmv NOx @ 15\% O2}}$ = \$148,005/year

B. NO_X Emission Reductions

The NO_X emissions can be converted from ppmv to lb/MMBtu using the following equation:

EF = ppm x MW x 1/379.5 x off x [20.9 / (20.9 – O_2%)]

Where:

- ppm is the emission concentration in ppmvd @ 15% O_2
- MW is the molecular weight of the pollutant (MW_{NOX} = 46 lb/lb-mol)
- 379.5 is the molar specific volume (lb/MMscf, at 60 °F)
- ff is the F-factor for natural gas/propane (8,578 scf/MMBtu, at 60 °F)
- O_2 is the stack oxygen content to which the emission concentrations are corrected (15%)

<u>DSE Option - 5.0 ppmv @ 15% O_2:</u>

EF (lb/MMBtu) = 5.0E-6 x 46 x 1/379.5 (lb-mol/MMscf) x 8,578 (scf/MMBtu) x [20.9 / (20.9 – 15)]
= 0.0184 lb-NO_X/MMBtu

<u>Technologically Feasible Option - 2.25 ppmv @ 15% O_2:</u>

EF (lb/MMBtu) = 2.25E-6 x 46 x 1/379.5 (lb-mol/MMscf) x 8,578 (scf/MMBtu) x [20.9 / (20.9 – 15)]
= 0.0083 lb-NO_X/MMBtu

Using the total burner rating of the turbine and the duct burner proposed in this project (124.9 MMBtu/hr), the emission reductions generated by installing control equipment capable of achieving NO_X emissions of 2.25 ppm @ 15% O_2 are as follows:

NO_X Reductions = (DSE NO_X EF – Tech Feasible NO_X EF) x 124.9 MMBtu/hr x 8,760 hr/year
NO_X Reductions = (0.0184 lb/MMBtu – 0.0083 lb/MMBtu) x 124.9 MMBtu/hr x 8,760 hr/year

NO_X Reductions = 11,051 lb/year

<u>C. Cost of NO_X Emission Reduction</u>

Cost of reductions = ($148,005/yr)/(11,051 lb/yr)(1 ton/2000 lb)
= **$26,786/ton of NO_X reduced**

As shown above, using an ultra conservative cost estimate for this control option shows that the cost of reducing NO_X emissions to 2.25 ppmv @ 15% O_2 would be greater than the $24,500/ton cost effectiveness threshold of the District BACT policy. This control option is therefore not cost effective and is being removed from consideration at this time.

In addition, since this control option is achievable with identical equipment to control technologically feasible option 1 above, NO_X emissions of 2.0 ppm @ 15% O_2, and an ultra conservative cost estimate shows that this option is not cost effective, it will be removed from consideration as a control alternative all together in this revised BACT analysis.

<u>Option 3 - 2.5 ppmv @ 15% O_2:</u>

The only remaining control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for the emission unit is determined to be NO_X emissions of less than or equal to 2.5 ppmv @ 15% O_2 (selective catalytic reduction or equal). The facility is proposing to install a new gas fired turbine equipped with a selective catalytic reduction system and expected NO_X emissions of less than or equal to 2.5 ppmvd @ 15% O_2. Therefore, BACT is satisfied for NO_X emissions and no further discussion is required.

II. SO_X Emissions:

a. Step 1 - Identify All Possible Control Technologies

The following references were consulted to determine the level of control that is currently being required.

CARB BACT Clearinghouse
EPA BACT/LAER Clearinghouse
SCAQMD BACT Clearinghouse
BAAQMD BACT Clearinghouse
SJVAPCD BACT Clearinghouse

The following Rules were also consulted:

SJVAPCD Rule 4703 (Stationary Gas Turbines)
SJVAPCD Rule 4801 (Sulfur Compounds)
SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines)
SCAQMD Rule 431.1 (Sulfur Content of Gaseous Fuels)
BAAQMD Regulation 9, Rule 9 (Nitrogen Oxides from Stationary Gas Turbines)
40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)

BACT Clearinghouse Survey:

District/ AQMD	Guideline or Application Number	Achieved-in-Practice	Technologically Feasible
SJVAPCD	3.4.3	PUC regulated natural gas, LPG, or non-PUC regulated gas with no more than 0.75 gr S/100 scf, or equal	N/A
SCAQMD	BACT Guidelines – Part D: Gas Turbine	No emission levels or controls for SO_X emissions listed	N/A
BAAQMD	89.1.5	Natural gas fuel	Natural gas fuel
CARB	Application Number 358625 (9.9 MW unit from a South Coast BACT analysis)	1.30 lb/hr[3]	N/A
EPA	No applicable determination for SO_X emissions located for turbines in this size range		

[3] Not enough information is available on CARB's BACT Clearinghouse website page to determine the maximum burner rating of this turbine system or if this emission rate includes emissions from duct burner firing. Therefore, a comparable emission factor cannot be established at this time. It will be assumed that no additional SO_X control devices are being required by South Coast AQMD for natural gas fired turbines within this size range and as a conservative estimate, the turbine referenced in this application was operating on PUC regulated natural gas.

Applicable Rules Survey:

District/AQMD	Rule	SO_X Limit
SJVAPCD	4703	Does not regulate SO_X
SJVAPCD	4801	2,000 ppmv (equivalent to approximately 2.85 lb-SO_X/MMBtu or a fuel sulfur content of 1,000 grains-S/100 scf
SCAQMD	1134	Does not regulate SO_X
SCAQMD	431.1	16 ppmv, as H_2S (equivalent to approximately 8 grains-S/100 scf)
BAAQMD	Reg 9, Rule 9	Does not regulate SO_X
EPA	Subpart KKKK	0.06 lb-SO_X/MMBtu

List of Other Control Options Found:

California Air Resources Board Guidance for the Permitting of Electrical Generation Technologies

The CARB document recommends that the PM_{10} BACT standard be set at the level that reflects the use of natural gas fuel with a fuel sulfur content of no more than 1 gr/100 scf. Since almost all of the SO_X that will be generated will come from the sulfur contained in the fuel, it can be concluded that had CARB made recommendations regarding the SO_X BACT standard, it would have been the use of natural gas fuel with the above referenced sulfur content limit.

Achieved-in-Practice Determination:

Existing SJVAPCD BACT guideline 3.4.3 lists AIP SO_X control to be the use of PUC regulated natural gas, LPG, or non-PUC regulated natural gas with a sulfur content of less than 0.75 grains-S/100 scf. This requirement is the most stringent requirement found of all of the referenced SO_X control options identified above. The District already has permitted turbines complying with this SO_X BACT requirement and Linn Operating is proposing to operate the proposed turbine on PUC quality natural gas fuel with a sulfur content of no more than 0.75 grains/100 scf. Therefore, the AIP BACT level for SO_X will be set equal to the following:

1. PUC regulated natural gas, LPG, or non-PUC regulated gas with no more than 0.75 gr S/100 scf

Technologically Feasible Control Alternatives:

The District did not locate any other data or information indicating that control devices for SO_X emissions that are more stringent than the AIP control option listed above are practically applicable for turbines rated between 3 MW and 10 MW. Therefore, no Technologically Feasible items will be considered.

b. Step 2 – Eliminate Technologically Infeasible Options

The only remaining control technology from step 1 above is technologically feasible.

c. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	PUC regulated natural gas, LPG, or non-PUC regulated gas with a sulfur content of no more than 0.75 gr S/100 scf	Yes

d. Step 4 – Cost Effectiveness Analysis

The only control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a gas turbine fired on PUC regulated natural gas, LPG, or non-PUC regulated natural gas with a sulfur content of no more than 0.75 grains-S/100 scf. The facility is proposing to operate a gas fired turbine fired on non-PUC regulated natural gas with a maximum sulfur content of 0.75 grains-S/100 scf. Therefore, BACT is satisfied for SO_X emissions and no further discussion is required.

III. PM_{10} Emissions:

a. Step 1 - Identify All Possible Control Technologies

The following references were consulted to determine the level of control that is currently being required.

CARB BACT Clearinghouse
EPA BACT/LAER Clearinghouse
SCAQMD BACT Clearinghouse
BAAQMD BACT Clearinghouse
SJVAPCD BACT Clearinghouse

The following Rules were also consulted:

SJVAPCD Rule 4703 (Stationary Gas Turbines)
SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines)
BAAQMD Regulation 9, Rule 9 (Nitrogen Oxides from Stationary Gas Turbines)
40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)

<u>BACT Clearinghouse Survey:</u>

District/ AQMD	Guideline or Application Number	Achieved-in-Practice	Technologically Feasible
SJVAPCD	3.4.3	Air inlet cooler, lube oil vent coalescer and natural gas fuel	N/A
SCAQMD	BACT Guidelines – Part D: Gas Turbine	No emission levels or controls for PM_{10} emissions listed for units rated between 3 MWe and 50 MWe	N/A
BAAQMD	89.1.5	Natural gas fuel	Natural gas fuel
CARB	Application Number 358625 (9.9 MW unit from a South Coast BACT analysis)	5.7 lb/hr[4]	N/A
EPA	No applicable determination for PM_{10} emissions located for turbines in this size range		

[4] Not enough information is available on CARB's BACT Clearinghouse website page to determine the maximum burner rating of this turbine system or if this emission rate includes emissions from duct burner firing. Therefore, a comparable emission factor cannot be established at this time. It will be assumed that no additional PM_{10} control devices are being required by South Coast AQMD for natural gas fired turbines within this size range and as a conservative estimate, the turbine referenced in this application was operating on PUC regulated natural gas.

Applicable Rules Survey:

District/AQMD	Rule	PM_{10} Limit
SJVAPCD	4703	Does not regulate PM_{10}
SCAQMD	1134	Does not regulate PM_{10}
BAAQMD	Reg 9, Rule 9	Does not regulate PM_{10}
EPA	Subpart KKKK	Does not regulate PM_{10}

List of Other Control Options Found:

California Air Resources Board Guidance for the Permitting of Electrical Generation Technologies

The CARB document recommends that the PM_{10} BACT standard be set at the level that reflects the use of natural gas fuel with a fuel sulfur content of no more than 1 gr/100 scf.

Achieved-in-Practice Determination:

Existing SJVAPCD BACT guideline 3.4.3 lists AIP for PM_{10} to be the use of an air inlet cooler, lube oil vent coalescer and natural gas fuel. This requirement is the most stringent requirement out of all of the referenced PM_{10} control options identified above. The District already has permitted facilities complying with this PM_{10} BACT requirement and Linn Operating is proposing to operate the proposed turbine with an air inlet cooler, lube oil vent coalescer and fire it on natural gas. Therefore, the AIP BACT level for PM_{10} will be equal to the following:

1. Air inlet cooler, lube oil vent coalescer, and natural gas fuel

Technologically Feasible Control Alternatives:

The District did not locate any other data or information indicating that control devices for PM_{10} emissions that are more stringent than the AIP control option listed above are practically applicable for turbines rated between 3 MW and 10 MW. Therefore, no Technologically Feasible items will be considered.

b. Step 2 – Eliminate Technologically Infeasible Options

The only remaining control technology from step 1 above is technologically feasible.

c. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	Air inlet cooler, lube oil vent coalescer, and natural gas fuel	Yes

d. Step 4 – Cost Effectiveness Analysis

The only control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a gas turbine equipped with an air inlet cooler, a lube oil vent coalescer and fired on natural gas fuel. The facility is proposing to operate a gas fired turbine fired equipped with an air inlet cooler, a lube oil vent coalescer and will be fired on natural gas. Therefore, BACT is satisfied for PM_{10} emissions and no further discussion is required.

IV. CO Emissions:

a. Step 1 - Identify All Possible Control Technologies

The following references were consulted to determine the level of control that is currently being required.

CARB BACT Clearinghouse
EPA BACT/LAER Clearinghouse
SCAQMD BACT Clearinghouse
BAAQMD BACT Clearinghouse
SJVAPCD BACT Clearinghouse

The following Rules were also consulted:

SJVAPCD Rule 4703 (Stationary Gas Turbines)
SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines)
BAAQMD Regulation 9, Rule 9 (Nitrogen Oxides from Stationary Gas Turbines)
40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)

<u>**BACT Clearinghouse Survey:**</u>

District/ AQMD	Guideline or Application Number	Achieved-in-Practice	Technologically Feasible
SJVAPCD	3.4.3	6.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)	N/A
SCAQMD	BACT Guidelines – Part D: Gas Turbine	10 ppmvd @ 15% O_2, for turbines rated between 3 MWe and 50 MWe	N/A
BAAQMD	89.1.5	6.0 ppmv, dry @ 15% O_2 (oxidation catalyst typical technology used)	N/A
CARB	Application Number 358625 (9.9 MW unit from a South Coast BACT analysis)	60 ppmvd @ 15 O_2	N/A
EPA	RBLC ID PA-0289 (55.62 MMBtu/hr heat and power combustion turbine)	25 ppm @ 15% O2	N/A

Applicable Rules Survey:

District/AQMD	Rule	CO Limit
SJVAPCD	4703	200 ppmv @ 15% O_2
SCAQMD	1134	Does not regulate CO
BAAQMD	Reg 9, Rule 9	Does not regulate CO
EPA	Subpart KKKK	Does not regulate CO

List of Other Control Options Found:

California Air Resources Board Guidance for the Permitting of Electrical Generation Technologies

The CARB document recommends that for stationary gas turbines rated between 3 - 12 MW, the CO BACT standard be set 0.2 lb/MW-hr (6 ppmvd @ 15% O_2).

Achieved-in-Practice Determination:

Existing SJVAPCD BACT guideline 3.4.3 lists AIP CO as 6.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal). This requirement is the most stringent requirement out of all of the referenced CO control options identified above. The District already has permitted facilities complying with this CO BACT requirement and Linn Operating is proposing to operate the turbine with a CO catalyst and CO emissions of less than or equal to 6.0 ppmv @ 15% O_2. Therefore, the AIP BACT level for CO will be equal to the following:

1. 6.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)

Technologically Feasible Control Alternatives:

The District did not locate any other data or information indicating that control devices for VOC emissions that are more stringent than the AIP control option listed above are practically applicable for turbines rated between 3 MW and 10 MW.

In addition, CO and NO_X emissions are generally inversely related for combustion sources. Thus, requiring a lower CO emissions rate could result in an increase in NO_X emissions from this source category. The District's attainment plan for ozone identifies the reduction of NO_X emissions as the most effective path towards attainment with State and Federal ozone Standards. Additionally, NO_X emissions contribute to PM_{10} and $PM_{2.5}$ pollution in the San Joaquin Valley. Therefore, the District is not going to consider additional controls for CO emissions or a reduction in the current CO BACT of 6.0 ppmv @ 15% O_2.

Therefore, no Technologically Feasible items will be considered.

b. Step 2 – Eliminate Technologically Infeasible Options

The only remaining control technology from step 1 above is technologically feasible.

c. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	6.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)	Yes

d. Step 4 – Cost Effectiveness Analysis

The only control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for the emission unit is determined to be CO emissions of less than or equal to 6.0 ppmv @ 15% O_2 (catalytic oxidation or equal). The facility is proposing to install a new gas fired turbine equipped with a CO catalyst and expected CO emissions of less than or equal to 6.0 ppmvd @ 15% O_2. Therefore, BACT is satisfied for CO emissions and no further discussion is required.

V. VOC Emissions:

a. Step 1 - Identify All Possible Control Technologies

The following references were consulted to determine the level of control that is currently being required.

CARB BACT Clearinghouse
EPA BACT/LAER Clearinghouse
SCAQMD BACT Clearinghouse
BAAQMD BACT Clearinghouse
SJVAPCD BACT Clearinghouse

The following Rules were also consulted:

SJVAPCD Rule 4703 (Stationary Gas Turbines)
SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines)
BAAQMD Regulation 9, Rule 9 (Nitrogen Oxides from Stationary Gas Turbines)
40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)

BACT Clearinghouse Survey:

District/ AQMD	Guideline or Application Number	Achieved-in-Practice	Technologically Feasible
SJVAPCD	3.4.3	2.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)	N/A
SCAQMD	BACT Guidelines – Part D: Gas Turbine	No emission levels or controls for VOC emissions listed for units rated between 3 MWe and 50 MWe	N/A
BAAQMD	89.1.5	2.0 ppmv, dry @ 15% O_2 (oxidation catalyst typical technology used)	Natural gas fuel
CARB	Application Number 358625 (9.9 MW unit from a South Coast BACT analysis)	4.50 lb/hr(5)	N/A
EPA	RBLC ID PA-0289 (55.62 MMBtu/hr heat and power combustion turbine)	0.60 lb/hr (equivalent to 0.0108 lb-VOC/MMBtu and 8.4 ppmv @ 15% O_2)	N/A

(5) Not enough information is available on CARB's BACT Clearinghouse website page to determine the maximum burner rating of this turbine system or if this emission rate includes emissions from duct burner firing. Therefore, a comparable emission factor cannot be established at this time. Based on this table above, it will be assumed that no additional VOC control devices are being required by South Coast AQMD for natural gas fired turbines within this size range and as a conservative estimate, the turbine referenced in this application was operating on PUC regulated natural gas.

Applicable Rules Survey:

District/AQMD	Rule	VOC Limit
SJVAPCD	4703	Does not regulate VOC
SCAQMD	1134	Does not regulate VOC
BAAQMD	Reg 9, Rule 9	Does not regulate VOC
EPA	Subpart KKKK	Does not regulate VOC

Other VOC Emission Control Options:

California Air Resources Board Guidance for the Permitting of Electrical Generation Technologies

The CARB document recommends that for stationary gas turbines rated between 3-12 MW, the VOC BACT standard be set 0.04 lb/MW-hr (2 ppmvd @ 15% O_2).

Achieved-in-Practice Determination:

Existing SJVAPCD BACT guideline 3.4.3 lists AIP VOC as 2.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal). This requirement is the most stringent requirement out of all of the referenced VOC control options identified above. The District already has permitted facilities complying with this VOC BACT requirement and Linn Operating is proposing to operate the turbine with a CO catalyst and VOC emissions of less than or equal to 2.0 ppmv @ 15% O_2. Therefore, the AIP BACT level for VOC will be equal to the following:

1. 2.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)

Technologically Feasible Control Alternatives:

The District did not locate any other data or information indicating that control devices for VOC emissions that are more stringent than the AIP control option listed above are practically applicable for turbines rated between 3 MW and 10 MW. Therefore, no Technologically Feasible items will be considered.

b. Step 2 – Eliminate Technologically Infeasible Options

The only remaining control technology from step 1 above is technologically feasible.

c. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	2.0 ppmv @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)	Yes

d. Step 4 – Cost Effectiveness Analysis

The only control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for the emission unit is determined to be VOC emissions of less than or equal to 2.0 ppmv @ 15% O_2 (catalytic oxidation or equal). The facility is proposing to install a new gas fired turbine equipped with a CO catalyst and expected VOC emissions of less than or equal to 2.0 ppmvd @ 15% O_2. Therefore, BACT is satisfied for VOC emissions and no further discussion is required.

Appendix I

Proposed Pages for the BACT Clearinghouse

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.3*

Emission Unit: Gas Turbine with Heat Recovery

Industry Type: All

Last Update: TBD

Equipment Rating: => 3 MW and =< 10 MW

	Achieved in Practice or contained in SIP	**Technologically Feasible**	**Alternate Basic Equipment**
NO_X	2.5 ppm @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal)	2.0 ppm @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal)	
SO_X	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf, or equal		
PM_{10}	Air inlet cooler, lube oil vent coalescer, and natural gas fuel		
CO	6.0 ppm @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)		
VOC	2.0 ppm @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in 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 3.4.3E

Emission Unit: Gas Turbine with Heat Recovery

Equipment Rating: 3 MW to 10 MW

References: ATC #: S-1246-415-0
Project #: S-1151996

Facility: Linn Operating, Inc.

Location: Heavy Oil Western Stationary Source in Kern County, CA

Date of Determination: TBD

Pollutant	BACT Requirements
NO_X	2.5 ppm @ 15% O_2, based on a three-hour average (selective catalytic reduction or equal)
SO_x	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf, or equal
PM_{10}	Air inlet cooler, lube oil vent coalescer, and natural gas fuel
CO	6.0 ppm @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)
VOC	2.0 ppm @ 15% O_2, based on a three-hour average (catalytic oxidation or equal)

BACT Status:

_x_ Achieved in practice __ Small Emitter __ T-BACT
___ Technologically feasible BACT
___ 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: *NO_X emissions of 2.0 ppmv @ 15% O_2*
___ Alternate Basic Equipment
Not evaluated for units that are being modified
___ The following alternate basic equipment was not cost effective:

Appendix II

Current SJVAPCD BACT Guideline 3.4.3

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.3*

Last Update: 1/18/2005

Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	2.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal)		
SOx	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf, or equal		
PM10	air inlet cooler, lube oil vent coalescer, and natural gas fuel		
NOx	2.5 ppmv @ 15% O2, based on a three-hour average (selective catalytic reduction or equal)		
CO	6.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal)		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is 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**

Appendix III

Solar's Dry Low Emissions Technology Capability and Experience

Solar's Dry Low Emissions Technology, Capability and Experience

Solar Turbines

A Caterpillar Company

Contents

Solar's Dry Low Emissions Technology, Capability and Experience

L.H. Cowell
SoLoNOx NPI Team Leader

D.M. Stansel
Group Manager, *SoLoNOx* Sustaining

R. Srinivasan
Group Manager, NPI & Combustion Technology

INTRODUCTION

The trend to lower gas turbine emission levels over the last 35 years has been driven by regulation, competition, and customer needs. Regulatory requirements are ever changing and vary significantly around the world. The gas turbine industry has responded to the need of the industry to meet these lower emission levels. Since the early 1990s, gas turbine manufacturers have introduced dry low emissions (DLE) gas turbine products based on lean-premixed combustion. Solar has been a leader in low emissions combustion systems and has placed more than 3000 gas turbines into service that incorporate its *SoLoNOx*™ DLE system.

Despite the significant improvement in gas turbine emissions, regulatory agencies continue to consider and implement more stringent requirements. As technology advances and regulatory levels continue to ratchet down, Solar is positioning itself to be technically prepared for future emissions requirements by continuing its significant investment in the development of technologies that will meet the anticipated market needs.

This paper provides a broad overview of Solar's low emissions technology and the recent developments that are enabling Solar to provide products that meet custom emissions requirements.

LEAN-PREMIXED COMBUSTION

Solar's *SoLoNOx* system employs lean-premixed combustion to reduce nitrogen oxides (NOx) emissions. Lean-premixed combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustion flame temperature. Since NOx formation rates are strongly dependent on flame temperature, lowering flame temperature (by lean operation) is an extremely effective strategy for reducing NOx emissions (Figure 1). Further reductions in emissions are achieved by premixing the fuel and combustor airflow upstream of the combustor primary zone. This premixing prevents local hot spots within the flame.

There are five aspects of lean-premixed combustion that are discussed in the subsequent sections:

- CO / NOx Tradeoff
- Operating Range
- Combustor Instability
- Ambient Operating Range
- Fuel Composition Variation

CO / NOx Tradeoff

Since the optimum flame temperature of a lean-premixed combustor is close to the lean flammability limit, lean-premixed combustor performance is characterized by a CO / NOx tradeoff (Figure 2). At the combustor design point, both CO and NOx are below target levels. However, deviations from the design point flame temperature cause emissions to increase. A reduction in temperature tends to in- crease CO emissions due to incomplete combustion; an increase in temperature will increase NOx. This tradeoff must be addressed during part-load turbine operation when the combustor is required to run at an even leaner condition overall. The tradeoff also comes into play in development efforts to reduce lean-premixed combustor NOx emissions by further reducing the primary zone design point temperature.

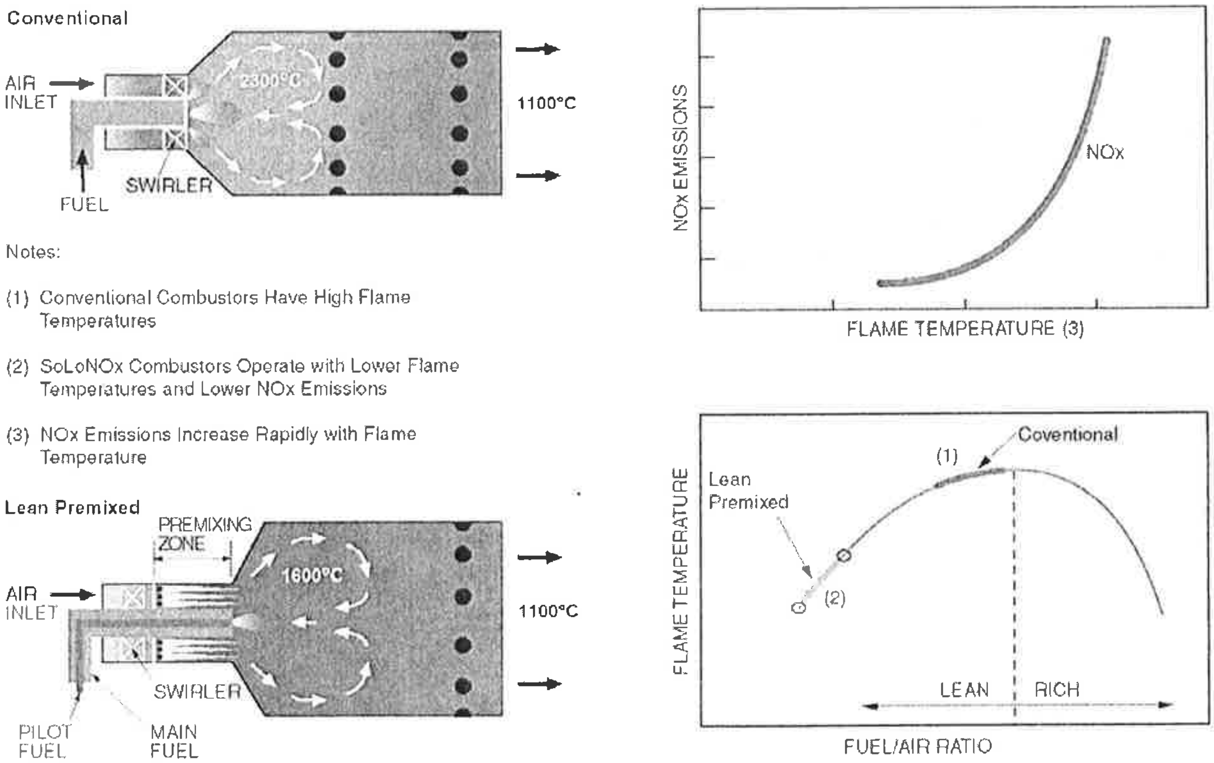

Figure 1. How Lean-Premixed Combustion Reduces NOx Emissions

Combustor Operating Range

Without any engine control to maintain a constant flame temperature, as a gas turbine moves away from full-load operation, a lean-premixed combustor will quickly produce increased CO emissions, the combustion will become unstable, and flame-out will ultimately occur. To broaden the operating range, low emission gas turbines use combustor air-flow control within the gas turbine to maintain a nearly constant flame temperature.

Combustor airflow control is achieved with compressor air bleed at part-load for two-shaft engines. Compressor bleed air is vented to the exhaust stack of the gas turbine package. Single-shaft gas turbines use the inlet guide vanes (IGV) to restrict airflow entering the combustor at part load. Unfortunately, regulating the IGV is not effective on two-shaft gas turbines.

Combustion Instability

A characteristic of lean-premixed combustion systems, experienced by all gas turbine manufacturers, is combustion instabilities. These occur as either low-frequency combustor "rumble" or higher-frequency combustor pressure oscillations.

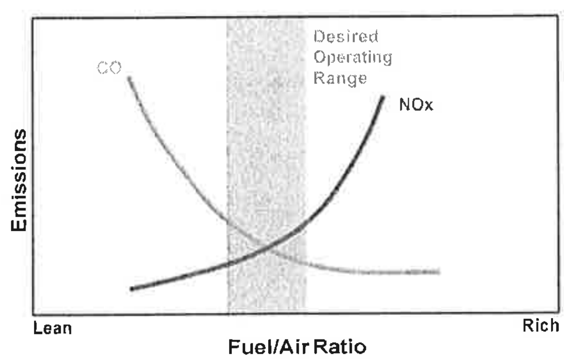

Figure 2. Typical Lean-Premixed Combustor Emissions

Simply put, lean flames have a greater tendency to cause combustion instabilities that can lead to engine damage if not addressed. It is recognized that the reduced stability of a lean-premixed flame contributes to these oscillations.

A successful DLE gas turbine has addressed combustor instabilities during product development to be certain that high level pressure oscillations do not occur during normal operation at any operating condition. Solar has been very successful at dealing with both combustor rumble and pressure oscillations with *SoLoNOx*.

Ambient Operating Range

The lean-premixed combustion system must be capable of operating over a broad range of ambient conditions. Changes in ambient conditions that affect the combustor primary zone temperature can influence emissions. Based on experience with conventional combustion, the ambient conditions that have the potential to impact emissions performance on DLE combustion systems include relative humidity, barometric pressure, and ambient temperature. Factory testing and field experience has shown that relative humidity and barometric pressure have only a minor effect on the combustor primary zone temperature and, thus, a nearly negligible influence on emissions from DLE gas turbines.

The influence of ambient temperature on emissions can be more significant. Ambient temperature has a direct impact on the primary zone temperature, but also influences how the DLE gas turbine is controlled. The gas turbine power and speed are limited differently as ambient temperature is reduced, which has a direct impact on full-load combustor primary zone temperature. In practice, emissions from *SoLoNOx* packages typically vary less than a few ppm from -29° to 38°C (-20° to 100°F). Figure 3 illustrates the relation between NOx and ambient temperature for a Titan™ 130 *SoLoNOx* operating at a compressor station in Canada. Similar data have been collected on Mars®, Taurus™70 and Taurus 60 *SoLoNOx* gas turbines.

For colder conditions, *SoLoNOx* packages are generally configured to increase pilot fuel flow at temperatures below -20°C (0°F) to augment flame stability. Therefore, below -20°C (0°F) the NOx and CO emissions increase. Because of this, the standard emissions warranty is limited to ambient temperatures above -20°C (0°F).

In order to compensate for changes in ambient conditions, *SoLoNOx* packages are required in factory test to operate with an emissions margin below the warranty level. For part-load operation, the engine low emission control system includes biasing for ambient temperature.

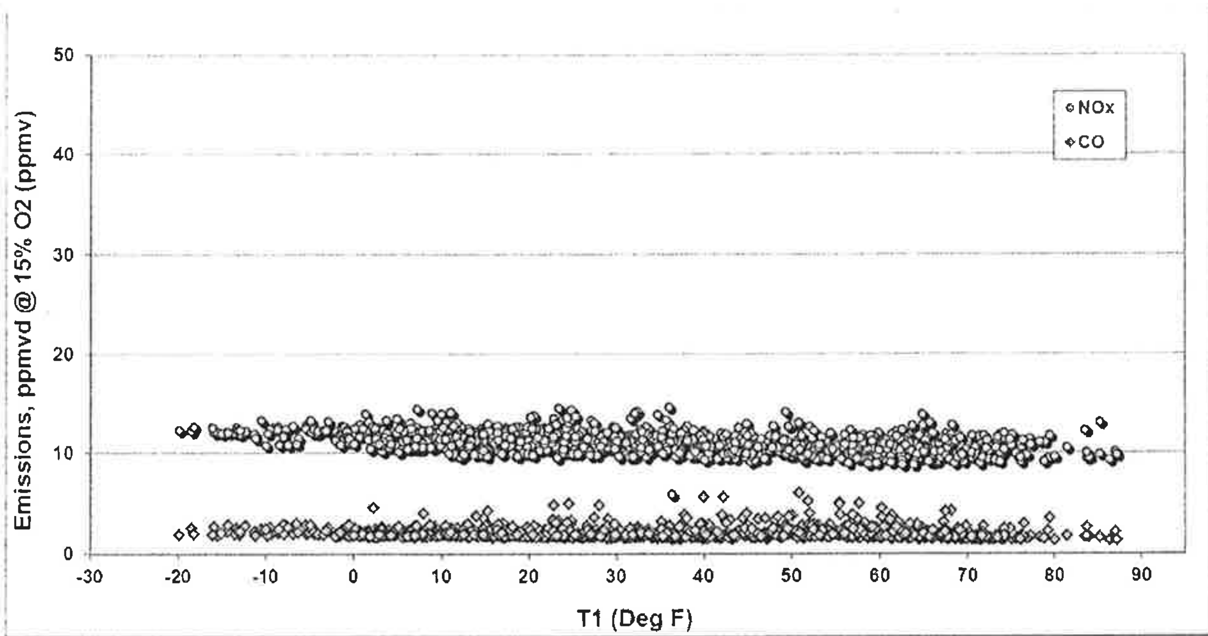

Figure 3. Emission Trends with Variation in Ambient Temperature on Titan 130 SoLoNOx Gas Turbine

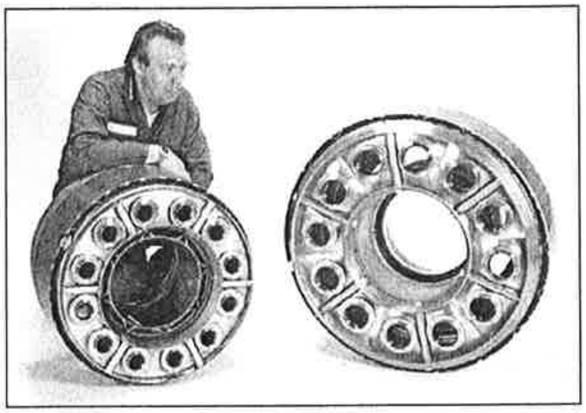

Figure 4. Conventional and SoLoNOx Combustor Liners

FUEL COMPOSITION VARIATION

The lean premixed combustion system must be capable of using fuels with variation in composition and properties. *SoLoNOx* gas turbines were designed to operate on "pipeline quality" natural gas and liquid distillate fuels such as #2 Diesel and kerosene as defined in Solar's Fuel Specification (ES9-98).

For lean premixed combustion systems gas fuels are characterized by Wobbe Index, auto ignition delay time, laminar flame speed and dew point. *SoLoNOx* engine testing has been completed with different gaseous fuel blends to represent the range of fuels found in pipeline applications with little measureable effect on emissions. Gas blends with broader variations in gas composition to simulate raw natural gas and gases associated with oil recovery have also been successfully operated in *SoLoNOx* gas turbines. A slight increase in NOx emissions is evident with more extreme variations in gas composition.

COMBUSTION SYSTEM DESCRIPTION

The unique *SoLoNOx* gas turbine components compared to a conventional combustion turbine include:

- Combustor liner
- Fuel injectors
- Combustor air management (bleed valve and inlet guide vane control)
- Control system
- Fuel delivery systems

Combustor Liner

The lean-premixed combustor liner is generally similar to a conventional liner in terms of geometry, materials and construction. The most significant difference is an increase in combustor volume (Figure 4). The larger volume is required to ensure complete combustion and low CO and UHC emissions at the lower overall flame temperature of the lean-premixed combustor. The increased combustor volume was achieved by increasing the outer liner diameter. The larger liner required an increase in the diameter of the combustor housing (Figure 5).

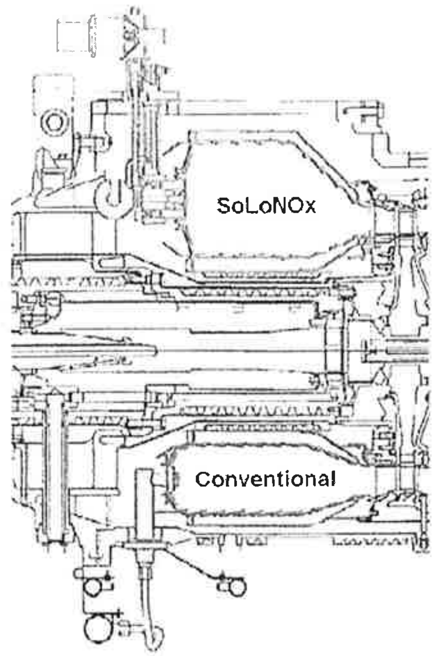

Figure 5. SoLoNOx and Conventional Combustion Systems.

A second difference in the lean-premixed liner is the absence of large air injection ports in the combustor primary zone. All air used in the combustion process is introduced through the air swirlers of the fuel injectors. The remaining air delivered by the compressor is used for cooling the walls or for dilution to achieve the specified radial temperature profile and pattern factor at the combustor exit.

Combustor liner cooling techniques used at Solar include film (louvered and effusion) and backside cooling.

Louver Cooling

First-generation production *SoLoNOx* combustors use louvers on the inside of the liner to direct air axially along the walls to produce a protective film of cooling air between the wall and the hot combustion gases (Figure 6). Combustor liners with louver cooling were used in Centaur® 50, Taurus 60, Taurus 70, and Mars gas turbines and many are still in service. The Centaur 40 is still produced with these combustor liners. The cooling air film gradually mixes with the hot gas stream;

thus, a succession of louvers must be placed along the liner to maintain the required temperatures. This method of wall cooling uses relatively high levels of cooling air because the wall just downstream of the louver must be overcooled in order to keep the wall adjacent to the next louver below the maximum temperature limit.

Effusion Cooling

A second generation combustor liner using effusion cooling was in production for Taurus 70, Mars and Titan 130 gas turbines and is still in use in many units in the field. Effusion cooling of the combustor walls uses 20% less cooling air compared to the louver cooled liner.

Reducing the liner cooling air resulted in a significant reduction of CO and UHC emissions. The injection of cooling air along the combustor wall can quench the combustion reactions in the wall region, thus contributing to CO and UHC emissions. This quenching process leads to high CO emissions because the CO, a combustion intermediate, is prevented from oxidizing to CO2.

The basic geometry of the effusion-cooled liner is the same as the louvered version. Effusion cooling is obtained by starting a film of air with a cooling louver at the front of the combustor and then continuously feeding this film with additional air through a multitude of small diameter holes drilled at a shallow angle to the wall surface (Figure 7).

Augmented Backside Cooled (ABC)

The current generation of combustor liners used in *SoLoNOx* Centaur 50, Mercury 50, Taurus 60, 65 & 70, Mars, Titan 130, and Titan 250 gas turbines applies Augmented Backside Cooling technology. The ABC technology does not promote reaction quenching and so, provides a two-fold benefit in terms of emissions. First, CO emissions are greatly reduced. Second, the lower CO levels allow combustor re-optimization to a lower flame temperature. This produces lower NOx levels along with the lower CO concentrations. Figure 8 shows how the ABC liner reduces CO emissions and the corresponding optimum fuel/air ratio reduces NOx emissions.

ABC liners forego cooling air injection into the combustor volume completely. Instead, combustor wall temperatures are controlled solely through convective cooling by a high velocity airstream on the cold side of the liner (Figure 9). In most instances, the high heat flux from the flame requires augmenting of the backside convective process to keep liner wall temperatures.

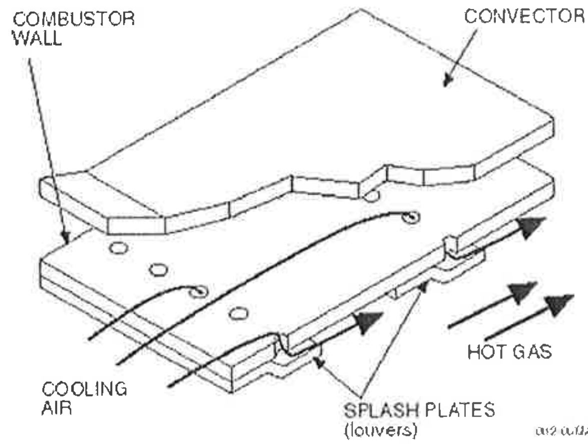

Figure 6. Louver Cooling Design

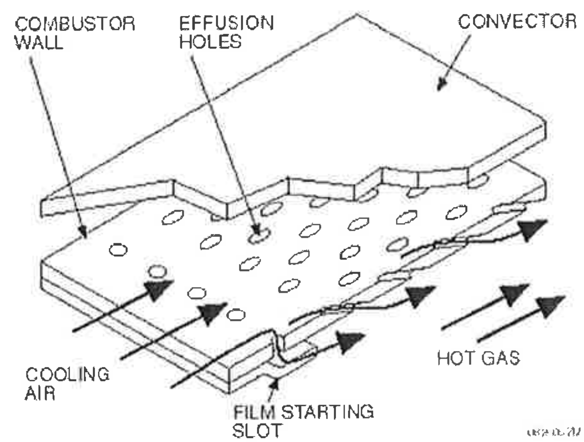

Figure 7. Effusion Cooling Design

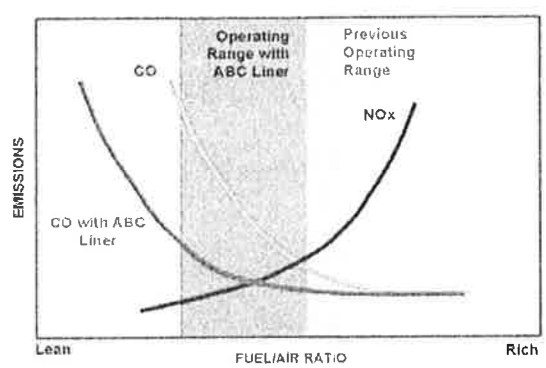

Figure 8. Extension of Design Range with ABC Combustor Liner for Low Emissions

This is accomplished with the use of impingement jets or turbulence generators in the form of trip strips, fins, and pins, which act to increase the cooling flow turbulence at the liner wall and augment the heat removal process.

An additional degree of liner protection is achieved through the application of a thermal barrier coating (TBC) on the hot sides of the liner walls. These TBCs are frequently composed of zirconia-based materials that are plasma-sprayed on the liner.

Acceptable liner durability is a key requirement of any liner cooling technique. It is determined by two factors: temperature and temperature gradient. Wall temperatures must be kept sufficiently low to prevent long-term oxidation or thermal creep. Solar's experience indicates that, in most circumstances, a wall temperature limit of 872°C (1600°F) provides excellent life. This criterion is applied to the design of all Solar gas turbine liners.

Excessive thermal gradients along the liner wall can lead to high stress concentration gradients that cause buckling or cracking. The thermal gradients in Solar's liners have been determined to be acceptable for long liner life. All three liner cooling configurations have demonstrated durability in excess of design targets.

Fuel Injectors

Incorporating lean-premixed combustion into gas turbines also required significant change to the fuel injector. As seen in Figure 10, *SoLoNOx* injectors are significantly larger than the conventional combustion counterpart. The size increase is required to accommodate higher airflow through the injector air swirler and the larger volume of the premixing chamber used to mix the fuel and air. The injector module includes a premixing main fuel injector and a pilot fuel injector.

SoLoNOx engine models use two different injector platforms based on the air swirler configuration. The Centaur 40 & 50, Mercury 50, Taurus 60 & 70, Mars, and Titan 130 gas turbines use an axial swirler where air enters axially along the injector centerline. The Taurus 65 and Titan 250 engines use a radial air swirler where the air enters perpendicularly to the injector centerline. The injector pictured in Figure 10a uses an axial swirler. Figure 10b is a photograph of a Titan 250 injector with a radial air swirler.

Main Fuel Circuit

The premixing main fuel injector uses the swirler to impart a high degree of swirl to the primary zone air. Natural gas is injected into the air through multiple spatially distributed orifices. Uniform mixing of the fuel and air occurs within the annular premixing chamber prior to reaching the combustor primary zone. The strong swirl stabilizes the combustion process in the primary zone by establishing a recirculation zone that draws reacted hot gases back upstream, thus providing a continuous ignition source. Lowest emissions are achieved at higher engine load, when more than 90% of the fuel is introduced through the main fuel circuit.

Pilot Fuel Circuit

The pilot fuel circuit within the injector provides partial premixing of air and fuel prior to combustion. During light-off and low-load operation, a substantial percentage of the fuel passes through the pilot circuit, providing a rich fuel/air mixture.

Combustor stability is enhanced in this mode compared to lean-premixed operation, although NOx and CO emissions are higher. Above 40 to 50% engine load, the pilot fuel is reduced to less than 10% of the total fuel flow to optimize emissions performance. The pilot fuel may also be momentarily increased during significant load transients to help stabilize the flame.

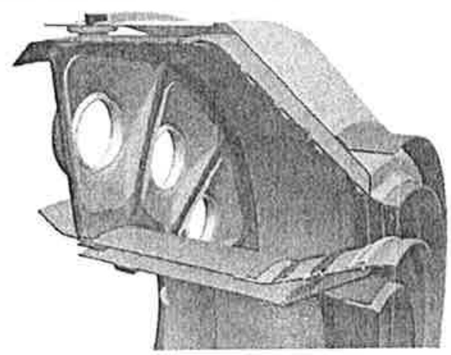

Figure 9. ABC Combustor Cross Section

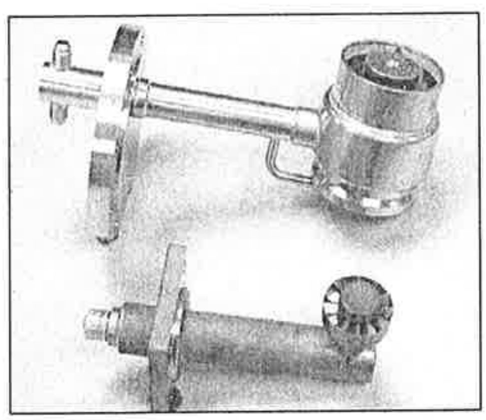

Figure 10a. Comparison of Taurus 60 SoLoNOx and Conventional Combustion System Fuel Injectors

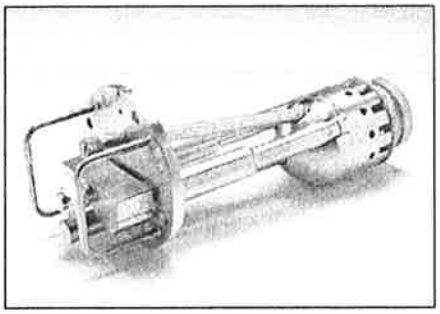

Figure 10b. Titan 250 Fuel Injector

Combustor Air Management

Three techniques are currently used on *SoLoNOx* engines to control the airflow to maintain the primary zone fuel/air ratio to its optimum, low-emissions level during part-load engine operation. Two of the techniques, used on all the engine models except the Mercury 50, are applied based on the engine shaft configuration. For reference two shaft engines are generally used for compressor set or mechanical drive package applications while single shaft engines are typically used for generator sets. The exceptions are for the Mars and Titan 250 gas turbines that are only available in a two shaft configuration and hence are used for all package applications.

In two-shaft gas turbines, the amount of air entering the combustor is regulated by bleeding air from the combustor casing at part load. The amount of bleed air is regulated by a specialized bleed valve. Bleed air bypasses the turbine and is readmitted to the flow path in the exhaust collector. A consequence of air bleed, however, is a reduction in engine part-load thermal efficiency since the compressed bleed air no longer enters the turbine section of the engine.

Single-shaft gas turbines, maintain optimum primary zone fuel/air ratios by modulating the compressor inlet guide vanes (IGV). Closing the IGVs reduces the airflow through the engine compressor and combustor. Regulating IGVs for single-shaft engines to control combustor airflow has a minor reduction in part-load thermal efficiency. Unfortunately, IGV airflow management is not effective on two-shaft machines since, with a separate power turbine shaft, the gas producer turbine speed cannot be maintained with a reduction in compressor airflow at part load.

The resulting variation in emissions with engine load is shown in Figure 11a. The combustor airflow management is active from approximately 50 - 100% load. The system is operated to maintain the optimum flame temperature over this load range. At lower loads, the pilot is increased and the combustor air management control algorithm is curtailed. A corresponding increase in emissions is evident.

For the Titan 250 the bleed valve control has been improved to extend combustor air flow to 40% load. In addition, the bleed valve is actively controlled down the idle. The pilot is increased at a slower rate as engine load is decreased from 40% load to idle. The corresponding emissions signature for the Titan 250 is significantly lower at lower loads when compared to the other engine models as depicted in Figure 11b.

The third combustor air management technique is used exclusively by the Mercury 50. This recuperated gas turbine makes use of an air diverter valve (ADV) located in the engine flow path to directly control the split of airflow between liner and injectors over the engine load range. This technique allows more precise control of primary zone temperature, and is an integral part of the Mercury 50's ability to guarantee single digit NOx emissions. The design also allows the Mercury 50 to operate with a high thermal efficiency over the full load range.

Control System

Engine controls have also been changed to incorporate *SoLoNOx*. This includes the capability to regulate the combustor airflow and pilot fuel flow over the engine operating map. The requirement to control these two parameters has added modest complexity to the *SoLoNOx* control system that is not required for a conventional engine, but can be easily handled by modern control systems.

During start-up and low-load operation, the pilot flow rate has been optimized to achieve maximum flame stability for the most rapid and flexible transient capability. Over the low emissions load range the control system modulates either the bleed valve or IGV to keep the combustion primary zone temperature within a specified range to operate with a low emissions signature.

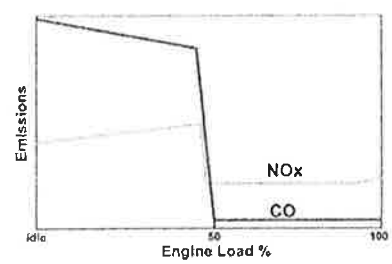

Figure 11a. Emission Trends with Variation in Engine Load for all SoLoNOx Engine Models Except Titan 250.

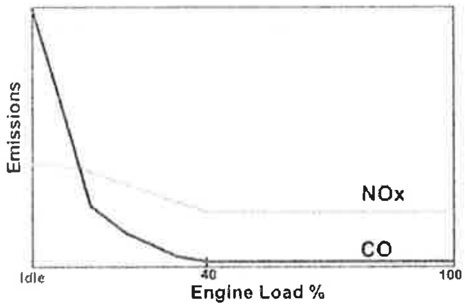

Figure 11b. Emission Trends for Titan 250

Accurate control of the primary zone temperature is critical to controlling NOx and CO emissions. *SoLoNOx* requires highly accurate electric actuators to ensure repeatable and precise emissions control. The benefits of using precise actuators extend beyond emissions to other elements of engine performance and transient response. The *SoLoNOx* gas turbine controls use the power turbine inlet temperature (T5) as an indirect measurement of the primary zone temperature to control the bleed valve or IGV position as a function of engine load.

A robust system for measuring combustor instabilities is included with *SoLoNOx* packages to measure combustor pressure oscillation and rumble amplitudes. The Burner Acoustic Monitor (BAM) alarms when oscillations or rumble exceed threshold values. *SoLoNOx* gas turbines go through extensive development and qualification to validate that combustion instabilities will not occur under normal operating conditions. Solar's experience is that when instabilities occur in the field they are most often due to fuel quality issues causing injector plugging or incorrect set-up or functioning of the fuel and bleed system hardware or controls.

FUEL DELIVERY SYSTEMS

Solar's SoLoNOx gas turbines also included changes to the fuel system.

Gas-Only Fuel System

The natural gas fuel system for *SoLoNOx* gas turbines includes two separate fuel circuits: one for the pilot system and one for the main. Separate fuel manifolds are used to supply pilot and main gas to the respective fuel circuits of each fuel injector. The fuel flow split between main and pilot is controlled with an accurate and fast response electronic valve on the pilot line. High quality, accurate, precise and fast fuel valves are required for *SoLoNOx*. During start-up and low-load operation, higher flow rates of pilot are used. When the engine is in the low-emissions mode, the pilot fuel valve throttles the pilot fuel flow to low levels. The low-pilot flow is still required to stabilize the flame.

Dual Fuel Systems

SoLoNOx gas turbines with dual fuel capability are designed to accommodate natural gas and light distillates. These systems employ unique fuel injectors with main and pilot fuel delivery flow paths for both gas and liquid. The injector design basis is similar to the gas only injector previously described, with many of the gas injection features identical on both. As with gas injection, the main liquid is premixed with the injector swirler air to burn in a lean premixed, low-emissions mode. Liquid fuel is injected into the premixing passage through multiple points for uniform distribution. Liquid pilot fuel is introduced through an airblast atomizer that injects directly into the primary zone of the combustor and burns as a stable diffusion flame. Liquid pilot is used to augment flame stability and support engine transients, as was described for the gas only engines.

The gas turbine package fuel system for dual fuel *SoLoNOx* is based on the conventional dual fuel gas turbine package fuel system and controls. Controls and a fuel distribution system have been added for pilot fuel injection capability. A pilot fuel splitter valve is used to regulate the amount of fuel flow between the main and pilot fuel passages.

A robust liquid fuel purge system has also been implemented for the *SoLoNOx* gas turbine package. Removing liquids from the injector after liquid fuel operation is essential to prevent injector fouling. Liquid remaining within the injector will form carbon and tar deposits that can block liquid passages.

EMISSION CAPABILITY

SoLoNOx gas turbines operate with a 10 to 20 fold decrease in NOx emissions when compared to the same engine model with conventional combustion. This benefit is shown graphically in Figure 12. The emissions options available for *SoLoNOx* engines models operating on pipeline natural gas for new production shipments are included in Table 1.

DLE GAS TURBINE FUEL FLEXIBILITY

Solar's *SoLoNOx* engines have been designed to operate on "pipeline quality" natural gas, diesel and kerosene. While these fuels are readily available in the industrialized world, large markets exist in developing countries and on offshore oil and gas platforms where the fuel composition is not as refined. Typically, these gas fuels contain higher concentrations of ethane, propane, and butane than a pipeline quality natural gas fuel. In addition, liquid fuels such as NGLs and naphtha's are also commonly used.

The fuel flexibility of *SoLoNOx* gas turbines has been extended to allow the use associated and raw natural gas fuel. Figure 24 indicates current *SoLoNOx* fuel capability for gas fuel Wobbe Index. With Solar's conventional combustion gas turbines an even broader range of fuels can be used both in terms of wobbe range and fuels composition. The challenges associated with using these fuels in DLE gas turbines include their influence on flame location within the premixing injector, combustor oscillations, and emissions performance. The *SoLoNOx* combustion system is being evaluated with these fuels.

Fuel Quality Considerations

In order to minimize gas turbine operational problems and maximize availability, the gas turbine manufacturer and the end-user must work closely together so that both parties fully understand what fuels will be used in the gas turbine to define the best combustion configuration for a specific application. Solar defines fuel quality requirements in the Engineering Specification ES 9-98. In addition, recommended fuel handling practices to control fuel contaminants are described in Product Information Letter (PIL 162).

DLE EXPERIENCE

Production Centaur, Taurus, Mars, Titan and Mercury *DLE* gas turbines are used extensively in the Oil & Gas and Power Generation industries. Applications include natural gas transmission, oil and gas platforms, continuous and peaking-duty simple-cycle and cogeneration power generation, and mechanical drives for many varieties of industrial and gas transmission applications. In these applications, *SoLoNOx* engines have offered reduced emissions capability from extremely low ambient temperatures in Alaska, Canada and Siberia to very hot conditions found in the deserts of the Arabian Peninsula. In addition, *SoLoNOx* applications using alternative fuels have become common with hundreds of applications using associated gases, and raw natural gases. The Mercury 50 has been used extensively in landfill and digester gas applications.

As of January 2015, cumulative *SoLoNOx* operating experience for all engine models has surpassed 209 million hours. This operating time has been gained on more than 3000 engines. This considerable experience illustrates how complete the market acceptance of *SoLoNOx* gas turbines has been. In addition, more than 375 dual fuel and liquid only *SoLoNOx* units have been sold.

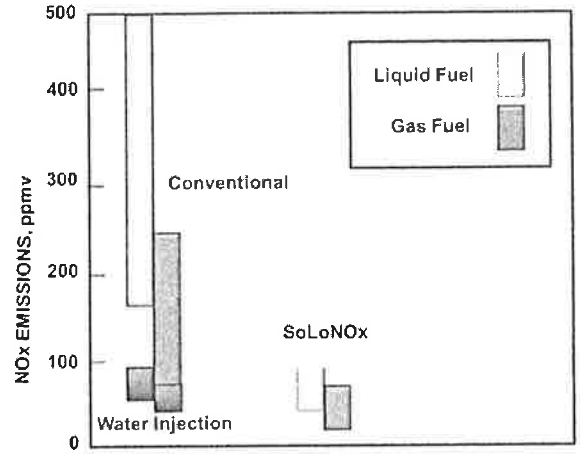

Figure 12. Comparison of NOx Emissions Performance between SoLoNOx and Conventional Combustion Gas Turbines

DLE GAS TURBINE ADVANCES

Emission regulations for industrial gas turbines continue to drive reductions in NOx, CO and UHC. Solar is continuing to invest in future DLE gas turbines that will be needed to meet these lower levels and to increase operating range with low emissions and fuel flexibility. The product strategy is that Solar continues DLE combustion development work a s the preferred approach to meet these future requirements as opposed to using exhaust clean up. From a life-cycle cost perspective, preventing pollutant formation has been shown to be more cost effective.

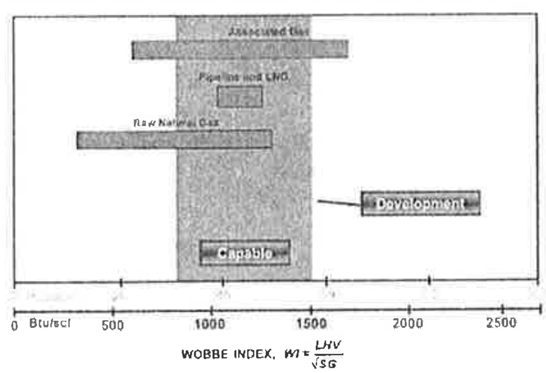

Figure 24. Gas Fuel Flexibility of Current (dark) and Future (light) SoLoNOx Gas Turbines

SUMMARY

Solar's *SoLoNOx* gas turbines and packages utilizing lean-premixed combustion have been in operation for more than 23 years. With an experience base of more than 3000 units, Solar remains an industry leader in DLE technology. *SoLoNOx* gas turbines are in service using a broad range of gas fuels (pipeline natural gas, associated gas, raw natural gas, digester and landfill gases) and liquid fuels including diesel #1 and #2 and kerosene. With pipeline natural gas standard emissions warranties are commonly offered as low as 15-ppm NOx and 25-ppm CO. It should be noted that the emission level that can be provided is contingent on review of site-specific project details such as fuel composition, ambient conditions, and operating profiles; ongoing support of warranty levels requires strict adherence to fuel quality requirements and gas turbine maintenance schedules.

Solar's emissions strategy continues to be focused on pollution prevention as the preferred approach to exhaust clean up. Development of the *SoLoNOx* combustion system is continuing to improve reliability, extend operational flexibility with low emissions, and increase fuel flexibility.

Solar is committed to remaining a DLE leader, offering gas turbine products that are environmentally compliant, durable, and cost effective. Solar intends to have gas turbine products available with the required emission reduction capability when customers need them.

Table 1. Gas Available Emissions Options – Natural Gas[1]

	Mercury™ 50		*Titan*™ 250 *Titan* 130 *Mars*® 100 *Mars* 90 *Taurus*™ 70 *Taurus* 65 *Taurus* 60 *Centaur*® 50		*Titan* 250 *Titan* 130 *Mars* 100 *Mars* 90 *Taurus* 70 *Taurus* 65 *Taurus* 60 *Centaur* 50 *Centaur* 40		*Titan* 250 *Titan* 130 *Mars* 100 *Mars* 90 *Taurus* 70 *Taurus* 60 *Centaur* 50 *Centaur* 40	
	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3	ppm	mg/Nm^3
NOx	5	11	15	30	25	50	38	80
CO	10	13	25	30	50	64	50	64
UHC	10	8	25	18	25	18	25	18
Load Range[2]	50-100%		50-100%		50-100%		50-100%	
Ambient Temperature	0 to 120°F (–20 to 49°C)		0 to 120°F (–20 to 49°C)		0 to 120°F (–20 to 49°C)		0 to 120°F (–20 to 49°C)	

Notes:

1. Gas fuel must meet or exceed the requirements of Solar's engineering specification ES9-98 "Fuel, Air, and Water (or Steam) for Solar Gas Turbine Engines"
2. The load range for the *Titan* 250 is 40-100%

Linn Operating, Inc.
5201 Truxtun Ave., Ste. 100
Bakersfield, CA 93309

April 5, 2016

San Joaquin Valley APCD
Attn. Dustin Brown
1990 E. Gettysburg Avenue
Fresno, CA 93726

Re: Linn Response – Request from San Joaquin Valley APCD for Input on NOx BACT Determination

Dear Dustin,

As requested, we have provided below our input on potential emissions variances associated with changing ambient temperature and engine loads, for turbines similar to Linn's planned Solar Taurus 60 units. The main source of this data is a publication by Solar Turbines titled "Solar's Dry Low Emissions Technology, Capability and Experience", which is also attached.

NOx Variance with Changing Engine Load

NOx emissions increase at higher engine loads (say over 90%), as shown in the "Figure 11a" chart below, taken from the Solar publication referenced above. From 50-90% engine load, the NOx conditions are quite stable, due to control systems supporting the Solar SoLoNOx combustor technology. Below 50%, the SoLoNOx combustors are not effective, with NOx and CO emissions being significantly higher in that range. Our project would operate in that low load range briefly during start up, but otherwise at full load which increases NOx emissions slightly as shown in the chart below.

Gas compression applications, as in the "Figure 3" chart on the following page, will typically operate at 75 - 85% engine load, with lower levels of NOx than at full load.

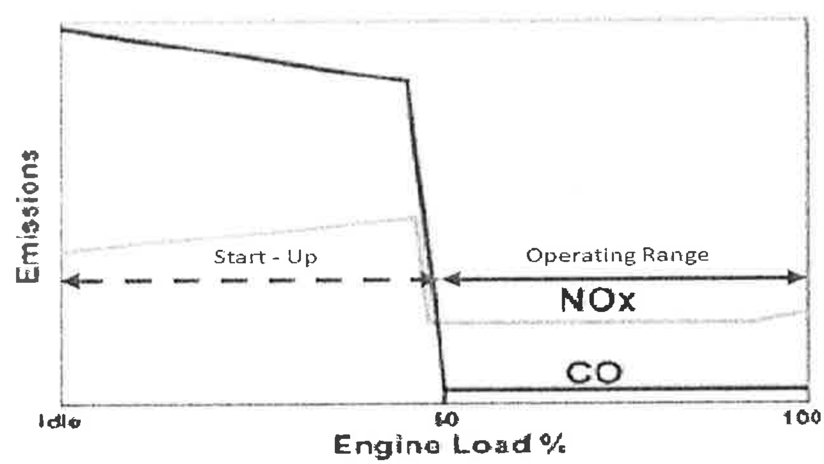

Figure 11a. Emission Trends with Variation in Engine Load for all SoLoNOx Engine Models Except Titan 250.

NOx Variance with Changing Ambient Conditions

NOx emissions vary with temperature and with other conditions (e.g., fuel quality, elevation, humidity, etc.) by as much as 6-7 ppm, over the target temperature range we anticipate for our planned Taurus 60 cogens. This is shown in the "Figure 3" chart below, taken from Solar's Dry Low Emission publication referenced earlier. The chart shows the lowest NOx levels occurring in the 55 – 75 deg F range, which would occur on average in the Spring or Fall months. Because as-needed grid backup power prices are typically lower in the Fall, operators may prefer Fall testing vs Spring.

This chart data is for a Solar Titan 130 Gas Turbine using SoLoNox combustors similar to those installed on the Taurus 60 units.

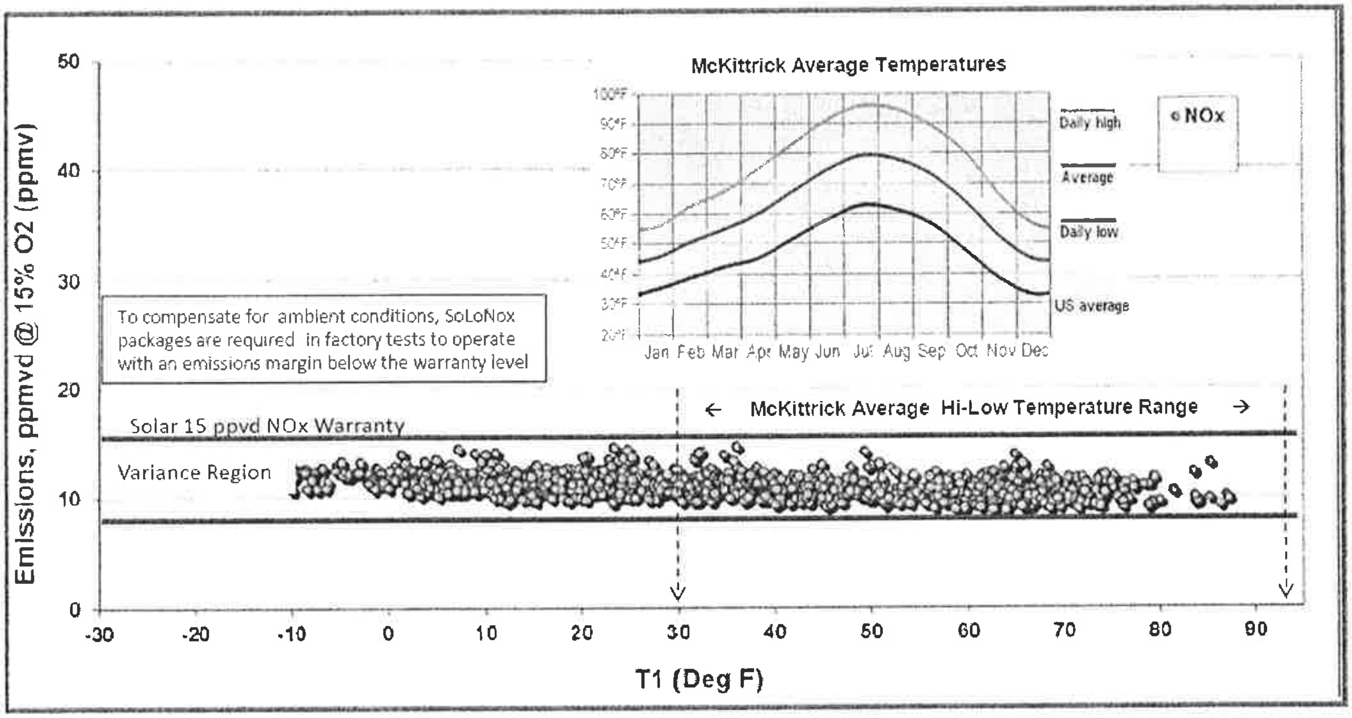

Figure 3. Emission Trends with Variation in Ambient Temperature on Titan 130 SoLoNOx Gas Turbine
(Gas Compression Application in Canada , typically running below full engine load)

In additional to economic viability considerations, these emissions variances during day to day operation require cogen equipment suppliers such as Solar Turbines and others to maintain a reasonable margin for emissions warranties, above the average or low NOx levels that operators may experience/report under more optimal operating conditions.

We trust this is helpful feedback and please contact me if you have any further questions.

Sincerely,

Shamim Reza
Se. EH&S Rep.

Attachment B

Statewide Compliance Certification

LINN Energy
NASDAQ:LINE
NASDAQ:LNCO

5201 Truxtun Ave.
Bakersfield, California 93309

Phone: (661) 616-3900

RECEIVED
APR 23 2015
SJVAPCD
Southern Region

April 06, 2015

Mr. Leonard Scandura
San Joaquin Valley Unified APCD
34946 Flyover Court
Bakersfield, CA 93308

RE: ATC Applications S- S-1246 Statewide Compliance Certification per District Rule 2201 Section 4.15.2

Dear Mr. Scandura:

Pursuant to the requirement of San Joaquin Valley APCD Rule 2201 section 4.15.2, Linn Operating, Inc. (Linn) submits this Compliance Certification regarding other owned, operated, or controlled major stationary sources in California. As of the date of this letter, Linn asserts that all major stationary sources owned or operated by Linn (or by any entity controlling, controlled by, or under common control with Linn) in California, which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

If you have any questions or require additional information please contact Mr. Shamim Reza at (661) 616-3889.

Sincerely,

Tim Crawford
Vice President California Region

Attachment C

Certificate of Conformity

RECEIVED

APR 23 2015

SJVAPCD
Southern Region

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: **Linn Operating. Inc.**	FACILITY ID: **S-1246, S-2265 & S-3585**
1. Type of Organization:[X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility	
2. Owner's Name: **Linn Operating. Inc.**	
3. Agent to the Owner: **Tim Crawford**	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial **all** circles for confirmation):

REB 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).

REB 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.

REB Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

REB 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:

Robert E. Boston — 3-24-15

Signature of Responsible Official — Date

Robert Boston

Name of Responsible Official (please print)

Manager of EHS

Title of Responsible Official (please print)

Attachment D

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Revised Risk Management Review

To:	Dustin Brown – Permit Services
From:	Leland Villalvazo – Technical Services
Date:	September 22, 2015
Facility Name:	Linn Operating, Inc.
Location:	Derby Acers
Application #(s):	S-1246-416-0
Project #:	S-1151997

A. RMR SUMMARY

RMR Summary				
Categories	**Cogen (Unit 416-0)**		**Project Totals**	**Facility Totals**
Prioritization Score	NA[1]		NA[1]	>1.0
Acute Hazard Index	5.90E-04		5.90E-04	0.7
Chronic Hazard Index	2.79E-05		2.79E-05	0.03
Maximum Individual Cancer Risk (10^{-6})	0.0024		0.0024	17.9
T-BACT Required?	**No**			
Special Permit Conditions?	**No**			

[1]Prioritization for this unit was not conducted since the facility total prioritization score is greater than 1.0.

Proposed Permit Conditions

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

Unit # 416-0

No special conditions are required.

B. RMR REPORT

I. Project Description

Technical Services received a request on May 28, 2015, to perform an Ambient Air Quality Analysis and a Risk Management Review to install one 67.9 MMBTU/HR natural gas-fired solar model Taurus 60 (T-60) turbine and one 57 MMBTU/HR natural gas-fired Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and heat recovery steam generator (HRSG).

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using Ventura County emission factors for internal combustion of natural gas were input into the HEARTs database. The AERMOD model was used with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP2) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 416-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	9.144	**Closest Receptor (m)**	Various
Stack Diameter. (m)	1.2192	**Type of Receptor**	Residential
Stack Exit Velocity (m/s)	19.394	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	375.928	**Fuel Type**	NG
Burner Rating (MMBtu/hr)	124.9		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were 265.8 lb/day CO, 30.0 lb/day NOx, 8.3 lb/day SOx, and 49.9 lb/day PM_{10}.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Diesel ICE	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]
$PM_{2.5}$	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 factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

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.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

Attachment E

Draft Authority to Construct Permit

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-1246-416-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: LINN OPERATING, INC
MAILING ADDRESS: 5201 TRUXTUN AVE, SUITE 100
BAKERSFIELD, CA 93309

LOCATION: HEAVY OIL WESTERN STATIONARY SOURCE
KERN COUNTY, CA

SECTION: 2 **TOWNSHIP:** 31S **RANGE:** 22E

EQUIPMENT DESCRIPTION:
5.67 MW (ISO RATED) COMBINED HEAT AND POWER COGENERATION SYSTEM CONSISTING OF ONE 67.9 MMBTU/HR NATURAL GAS-FIRED SOLAR MODEL TAURUS 60 (T-60) TURBINE AND ONE 57 MMBTU/HR NATURAL GAS-FIRED RENTECH DUCT BURNER WITH RENTECH SELECTIVE CATALYTIC REDUCTION (SCR) AND CO CATALYST AND HEAT RECOVERY STEAM GENERATOR (HRSG)

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. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOx emission reduction credits for the following quantity of emissions: 1st quarter - 3,724 lb, 2nd quarter - 3,724 lb, 3rd quarter - 3,725 lb, and fourth quarter - 3,725 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter - 878 lb, 2nd quarter - 878 lb, 3rd quarter - 878 lb, and fourth quarter - 878 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 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

DRAFT

Arnaud Marjollet, Director of Permit Services
S-1246-416-0 Jul 20 2016 9:31AM -- BROWND Joint Inspection NOT Required

5. Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 6,974 lb, 2nd quarter - 6,974 lb, 3rd quarter - 6,974 lb, and fourth quarter - 6,974 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.000 lb-SOx: 1.0 lb-PM10. [District Rule 2201] Federally Enforceable Through Title V Permit

6. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,035 lb, 2nd quarter - 1,035 lb, 3rd quarter - 1,035 lb, and fourth quarter - 1,035 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

7. ERC Certificate Numbers S-4514-2, S-4515-2, S-4516-2, S-4530-2, N-1302-2, N-1332-2, S-4508-5, N-1307-5, N-1309-5, C-1353-5, S-4533-5, S-4539-5, N-1206-4, N-1312-4, S-4510-4, S-4583-4, N-1202-1, N-1295-1, N-1296-1, N-1297-1, S-4500-1, S-4502-1, S-4504-1 (or a certificate split from these certificates) shall be used to supply the required 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. 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

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. 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] Federally Enforceable Through Title V Permit

12. {1898} 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]

13. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit

14. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201] Federally Enforceable Through Title V Permit

15. The turbine and duct burner shall be fired on PUC-quality natural gas and/or ethane-rich natural gas and the natural gas shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [District Rules 2201 and 4801 and 40 CFR 60.4330] Federally Enforceable Through Title V Permit

16. During startup of the unit, emissions shall not exceed any of the following limits: 1.6 lb-NOx (as NO2)/startup; 0.053 lb-SOx (as SO2)/startup; 0.423 lb-PM10/startup; 79.3 lb-CO/startup; or 0.5 lb-VOC (as methane)/startup. [District Rule 2201] Federally Enforceable Through Title V Permit

17. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown); 0.024 lb-SOx (as SO2)/shutdown; 0.192 lb-PM10/shutdown; 34.7 lb-CO/shutdown; or 0.2 lb-VOC (as methane)/shutdown. [District Rule 2201] Federally Enforceable Through Title V Permit

18. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.13 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 1.65 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.31 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320] Federally Enforceable Through Title V Permit

19. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.12 lb/hr or 0.017 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

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

21. The duration of each startup or shutdown shall not exceed 22 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

22. The total duration of startup time shall not exceed either of the following: 44 minutes per day or 132 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit

23. The total duration of shutdown time shall not exceed either of the following: 20 minutes per day or 60 minutes per year. [District Rule 2201] Federally Enforceable Through Title V Permit

24. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

25. The ammonia slip (NH3) emissions shall not exceed either of the following limits: 0.56 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

26. Annual emissions from the turbine and duct burner system (as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: NOx: 9,932 lb/year (as NO2); SOx: 2,341 lb/year (as SO2); PM10: 18,597 lb/year; CO: 15,121 lb/year; VOC: 2,760 lb/year (as methane); or NH3: 4,922 lb/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201] Federally Enforceable Through Title V Permit

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

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

30. Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 60 days of startup and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4340 and 60.4400] Federally Enforceable Through Title V Permit

31. Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 60 days of startup. [District Rule 2201] Federally Enforceable Through Title V Permit

32. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703] Federally Enforceable Through Title V Permit

33. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081] Federally Enforceable Through Title V Permit

34. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081] Federally Enforceable Through Title V Permit

35. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

36. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400] Federally Enforceable Through Title V Permit

37. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

38. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703] Federally Enforceable Through Title V Permit

39. PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

40. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102] Federally Enforceable Through Title V Permit

41. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703] Federally Enforceable Through Title V Permit

42. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703] Federally Enforceable Through Title V Permit

43. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703] Federally Enforceable Through Title V Permit

44. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

45. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

46. The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit

DRAFT

CONDITIONS CONTINUE ON NEXT PAGE

47. If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703 and 40 CFR 60.4415] Federally Enforceable Through Title V Permit

48. The operator shall demonstrate compliance with the fuel sulfur content limit of 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas at least once per week. Once compliance is demonstrated for eight consecutive weeks, the frequency for demonstrating compliance with the fuel sulfur content may be reduced to once every calendar quarter. If a quarterly determination shows a violation of the sulfur content limit, then weekly demonstrations shall resume and continue until eight consecutive demonstrations show compliance. Once compliance is shown on eight consecutive weekly determinations, then determinations may return to quarterly. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Federally Enforceable Through Title V Permit

49. The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. If compliance is being demonstrated through fuel sulfur content testing, the testing shall occur at a location after all fuel sources are combined prior to combustion, or by performing mass balance calculations based on testing the sulfur content and volume of each fuel source. [40 CFR 60.4415(a)(1)(i)] Federally Enforceable Through Title V Permit

50. Excess SOx emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)] Federally Enforceable Through Title V Permit

51. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703] Federally Enforceable Through Title V Permit

53. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [40 CFR 60.7] Federally Enforceable Through Title V Permit

54. The permittee shall maintain a record of the cumulative 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201] Federally Enforceable Through Title V Permit

55. The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

56. The owner or operator shall submit a written report of excess emissions and monitoring downtime to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395] Federally Enforceable Through Title V Permit

57. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.7] Federally Enforceable Through Title V Permit

58. All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703] Federally Enforceable Through Title V Permit

Attachment F

Environmental Protection Agency (EPA) Comments and District Responses

EPA COMMENTS / DISTRICT RESPONSES

EPA comments regarding the preliminary decision for Linn Operating, Inc.'s (District facility S-1247) proposed project are provided below followed by the District's responses. A copy of EPA's November 12, 2015 comment email is available at the District office.

1. EPA COMMENT – Project PSD Significance Thresholds

Under Section VII.C.5, the District determines that the facility is a PSD major source for both VOC and CO. Under Section VII.C.9, the District evaluates whether the project is subject to PSD requirements. While the narrative correctly states that if the source is already a PSD major source, then a determination must be made as to whether the project will result in a significant emissions increase, this is not the evaluation which is performed. Instead this section evaluates whether the project will result in a new major source. The evaluation compares the emission increases from the project with the PSD major source thresholds, rather than the PSD significance thresholds. Please correct this table and the narrative to present the correct evaluation. EPA notes that for this project, the emission increases are below the PSD significance thresholds for each pollutant, therefore the project does not result in a PSD major modification and there is no change in the District's determination that PSD requirements do not apply.

DISTRICT RESPONSE

The District agrees with EPA's comment and has revised the PSD discussion in Section VII.C.9 of this document to reflect that this facility is an existing major source for PSD.

2. EPA COMMENT – Revised Top Down BACT Analysis

The District's evaluation states that BACT for NOx emissions is 2.5 ppm @ 15% O2, based on a three-hour average, citing District BACT Guideline 3.4.3 for Gas Turbines with Heat Recovery (=>3 MW and =< 10 MW). EPA notes however that this BACT guideline was last updated in 2005, making this determination over 10 years old. EPA believes that Gas Turbines in this size range can achieve a 2.0 ppm limit averaged over 3 hrs. Because the cited BACT document is out of date it does not represent a current top-down BACT analysis, as required by District rules. Therefore the District must perform a new top-down BACT analysis for this project, rather than relying on the outdated determination listed in BACT Guideline 3.4.3, prior to issuing the final ATC for this project. Please provide a copy of the revised BACT analysis to EPA prior to issuing the final ATC.

DISTRICT RESPONSE

The District agrees with EPA's comment and has performed a revised top-down BACT analysis for all criteria pollutants from natural gas fired turbines rated between 3 MW and 10 MW. The District has determined that NO_X emissions of 2.0 ppmv @ 15% O_2 is not currently being achieved in practice for this class and category of source. However, with appropriate system operation and design, NO_X emissions of 2.0 ppmv @ 15% O_2 is feasible. Therefore, the District has added NO_X emissions of 2.0 ppmv @ 15% O_2 as a technologically feasible control alternative to BACT guideline 3.4.3. The complete top-down BACT analysis has been included in Attachment A of this document.