San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

MAY 01 2013

Shams Hassan
E&B Natural Resources Management
3000 James Road
Bakersfield, CA 93308

Re: Notice of Preliminary Decision - ATC
Facility# S-1624
Project# 1130129

Dear Mr. Hassan:

Enclosed for your review is the District's engineering evaluation of an application for Authorities to Construct for E&B Natural Resources Management for its heavy oil central stationary source in Kern County, CA. The proposed ATCs are subject to the requirements of Rule 2201 – New and Modified Stationary Source Review and Rule 2410 – Prevention of Significant Deterioration.

The project authorizes two (2) 85 MMBtu/hr natural gas-fired steam generators.

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the Authority to Construct will be issued to the facility with a Certificate of Conformity.

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

If you have any questions, please contact Mr. Jim Swaney, Permit Services Manager, at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:RE/st

Enclosures

cc: distribution list

Distribution List

EPA/CARB – ALL PROJECTS

Gerardo C. Rios, Chief
Permits Office
Air Division
U.S. EPA - Region IX
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Eastern Kern APCD
c/o APCO
2700 "M" Street, Suite 302
Bakersfield, CA 93301

San Luis Obispo County APCD
c/o APCO
3433 Roberto Court
San Luis Obispo, CA 93401

Santa Barbara County APCD
c/o APCO
260 N. San Antonio Road #A
Santa Barbara, CA 93110-1315

South Coast AQMD
c/o APCO
21865 Copley Drive
Diamond Bar, CA 91765

Ventura County APCD
c/o APCO
669 County Square Dr., 2nd Fl.
Ventura, CA 93003

Newspaper notice for publication in the newspaper below and for posting on valleyair.org

Bakersfield

**NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
AN AUTHORITY TO CONSTRUCT AND
THE PROPOSED SIGNIFICANT MODIFICATION OF FEDERALLY
MANDATED OPERATING PERMIT AND PREVENTION OF SIGNIFICANT
DETERIORATION NOTIFICATION**

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to E&B Natural Resources Management operation in the heavy oil central stationary source, Kern County, CA. The proposed ATCs are subject to the requirements of Rule 2201 – New and Modified Stationary Source Review and Rule 2410 – Prevention of Significant Deterioration.

E&B Natural Resources Management is requesting Authorities to Construct (ATC) for two new 85 MMBtu/hr natural gas-fired steam generators and consideration for Potential of Significant Deterioration requirements. The proposed modifications will result in a significant emissions increase, subject to the requirements of Rule 2410, of 87,114 tons/year of CO_2e. There is no increment consumption of any pollutant.

The analysis of the legal and factual basis for this proposed action, Project #S-1130129, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and at any District office. This will be the public's only opportunity to comment on the specific conditions of the modification. If requested, the District will hold a public hearing regarding proposed issuance of the subject ATCs. For additional information, please contact the District at (661) 392-5500.

Written comments on the proposed project must be submitted by June 6, 2013 to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 34946 FLYOVER COURT, BAKERSFIELD, CA 93308-9725.**

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Two 85 MMBtu/hr steam generators

Facility Name:	E&B Natural Resources Management	Date:	April 29, 2013
Mailing Address:	3000 James Road Bakersfield, CA 93308	Engineer: Lead Engineer:	Richard Edgehill Allan Phillips
Contact Person:	Shams Hasan and Scott Faulkenburg		
Telephone:	(661) 676-6168 (SH), (661) 377-0073 (#15), 345-8263 (cellular)(SF)		
Fax:	(661) 616-6168		
E-Mail:	sfaulkenburg@ix.netcom.com		
Application #(s):	S-1624-254-0 and '-255-0		
Project #:	1130129		
Deemed Complete:	February 19, 2013		

I. Proposal

E&B Natural Resources Management (E&B) has requested Authorities to Construct (ATCs) for the installation of two 85 MMBtu/hr natural gas-fired steam generators. The increase in VOC emissions will be mitigated by cancelation of two fixed-roof crude oil storage tanks (S-1624-44 and '-69).

The facility is a major source and this project is a Federal Major Modification requiring BACT, offsets, and public notice.

Pursuant to Rule 2530 – Federally Enforceable Potential to Emit, even though the facility is a major source because the facility's actual emissions are currently less than ½ of the major source thresholds, they are not required to obtain a Title V permit.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2530	Federally Enforceable Potential to Emit (12/18/08)
Rule 2410	Prevention of Significant Deterioration (June 16, 2011)
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 4301	Fuel Burning Equipment (12/17/92)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase II (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase III (3/17/05)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)

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 steam generators will be located at Section 5, T28S, R27E in E&B Natural Resource Management's heavy oil central stationary source. The equipment will 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.

A project location map is included in **Attachment I**.

IV. Process Description (applicant email 3-6-13)

Produced fluids from Thermally Enhanced Oil Recovery (TEOR) Operations enter feed separators and crude oil processing tanks served by vapor control systems (VCSs). The gas collected from the separators and VCS systems is directed to a central gas line owned by E&B that supplies fuel to microturbines, heaters, steam generators, and permit exempt-engines. PUC gas from a gas utility is used to supplement the volume of existing field gas if necessary. The existing combustion units have existing permit conditions limiting gaseous sulfur content to 1 gr S/100 scf, which has been demonstrated by laboratory analysis.

Proposed Steam Generators
The proposed steam generators S-1624-254 and '-255 will be equipped with ultra-low NOx burners, 235 ft^2/MMBtu heat transfer surface area (CEQA requirement), and will be used to supply steam for (TEOR) Operations. Combusted gas will contain no more than 1.0 gr S/100scf.

V. Equipment Listing

~~S-1624-44-1: 250 BBL FIXED ROOF PETROLEUM STORAGE TANK, LBE #2~~

~~S-1624-69-1: 250 BBL FIXED ROOF PETROLEUM STORAGE TANK, GRIMES #4~~

S-1624-254-0: 85 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH NORTH AMERICAN 4231-85 GLE BURNER (OR EQUIVALENT) AND A FLUE GAS RECIRCULATION SYSTEM

S-1624-255-0: 85 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH NORTH AMERICAN 4231-85 GLE BURNER (OR EQUIVALENT) AND A FLUE GAS RECIRCULATION SYSTEM

As per District policy APR 1035 Flexibility in Equipment Descriptions in ATCs, some flexibility in the final specifications of the equipment is requested and will be allowed as stated in the following ATC conditions:

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

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

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

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

VI. Emission Control Technology Evaluation

Emissions from gas-fired steam generators include NO_X, CO, VOC, PM_{10}, and SO_X.

Low-NO_X burners reduce NO_X formation by producing lower flame temperatures (and longer flames) than conventional burners. Conventional burners thoroughly mix all the fuel and air in a single stage just prior to combustion, whereas low-NO_X burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NO_X. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

The use of flue gas re-circulation (FGR) can reduce nitrogen oxides (NO_X) emissions by 60 - 70%. In an FGR system, a portion of the flue gas is re-circulated back to the inlet air. As flue gas is composed mainly of nitrogen and the products of combustion, it is much lower in oxygen than the inlet air and contains virtually no combustible hydrocarbons to burn. Thus, flue gas is practically inert. The addition of an inert mass of gas to the combustion reaction serves to absorb heat without producing heat, thereby lowering the flame temperature. Since thermal NO_X is formed by high flame temperatures, the lower flame temperatures produced by FGR serve to reduce thermal NO_X.

Manufacturer's information on the low NOx burner is included in **Attachment II**.

VII. General Calculations

A. Assumptions

S-1624-254 and '-255

- The maximum operating schedule is 24 hours per day (per applicant)
- EPA F-factor for natural gas is 8,578 dscf/MMBtu (40 CFR 60, Appendix B)
- Natural/Field Gas Heating Value: 1,000 Btu/scf (District Practice)

S-1624-44 and '-69 (250 bbl crude oil storage tanks)

- The tanks emit only volatile organic compounds (VOCs)
- Tank vapor molecular weight, 100 lb/lbmol
- Parameters used in tank emissions calculations are listed in the following table:

	Diameter (ft)	Height (ft)	Throughput (bbl/day)	Tvp (psia)	Temperature (°F)
S-1624-44 and '-69	15.3	8	250	0.5	100

Additional assumptions are included in **Attachment III**.

B. Emission Factors

S-1624-44 and '-69

Both the daily and annual PE's were calculated using the District's Microsoft Excel spreadsheets for Tank Emissions - Fixed Roof Crude Oil less than 26° API. The tank emissions calculations are included in **Attachment III**.

S-1624-254 and 255

Pollutant	Post-Project Emission Factors (EF2)			Source
NO_X	6.0 lb-NO_X/MMscf	0.006 lb-NO_X/MMBtu	5 ppmvd NO_X (@ 3%O_2)	proposed
SO_X	2.85 lb-SO_X/MMscf	0.00285 lb SO2/MMBtu		District standard for natural gas
PM10	3.5 lb-PM10/MMscf	0.0035 lb-PM10/MMBtu		Proposed*
CO	37 lb-CO/MMscf	0.037 lb-CO/MMBtu	50 ppmv CO @3% O2	Proposed
VOC	5.5 lb-VOC/MMscf	0.0055 lb-VOC/MMBtu	13 ppmv VOC @3% O2	AP-42 (07/98) Table 1.4-2

*applicant email 3-28-13 and Section VII Source Testing

Startup/Shutdown (2 hr per occurrence)

Steam Generators S-1624-220-0, '221-0, '222-0, '223-0 and '224-0 Emission Factors			
Pollutant	Emission Factors		Source
NO_X	0.018 lb-NO_X/MMBtu	15 ppmv NO_X (@ 3%O2)	Rule 4306 emission limit

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Permit Unit	VOC - Daily PE2 (lb/day)	VOC - Annual PE2 (lb/Year)
S-1624-44	13.0	4,747
S-1624-69	13.0	4,747

S-1624-254 and '-255
Since this is a new emissions unit, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

S-1624-254 and '-155 (each)

Pollutant	Daily PE2			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/day)	Daily PE2 (lb/day)
NO_X	0.0061	85	24	see below
SO_X	0.00285	85	24	5.8
PM_{10}	0.0035	85	24	7.1
CO	0.037	85	24	75.5
VOC	0.0055	85	24	11.2

Pollutant	Annual PE2			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/year)	Annual PE2 (lb/year)
NO_X	0.006	85	8,760	4,542
SO_X	0.00285	85	8,760	2,122
PM_{10}	0.0035	85	8,760	2,606
CO	0.037	85	8,760	27,550
VOC	0.0055	85	8,760	4,095

Startup/Shutdown
NOx: 0.018 lb/MMBtu x 85.0 MMBtu/hr x 4 hr/day + 0.0061 x 85.0 MMBtu/hr x 20 hr/day = 16.5 lb/day

PE2		
	Daily Emissions (lb/day)	Annual Emissions (lb/year)
NO_X	16.5	4,542
SO_X	5.8	2,122
PM_{10}	7.1	2,606
CO	75.5	27,550
VOC	11.2	4,095

Greenhouse Gas Emissions

2 x 85 MMBtu/hr x 8760 hr/yr = 1,489,200 MMBtu/yr

CO2 Emissions = 1,489,200 MMBtu/yr x 116.89 lb/MMBtu
= 174,072,588 lb-CO2(eq)/yr
CH4 Emissions = 1,489,200 MMBtu/yr x 0.002 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4
= 62,546 lb-CO2(eq)/yr
N2O Emissions = 1,489,200 MMBtu/yr x 0.0002 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O
= 92,330 lb-CO2(eq)/yr

174,227,464 lb-CO2(eq)/yr/2000 lb/short ton x 0.9072 metric tons/short ton
= 79,030 metric tons-CO2(eq)/year > 230 metric tons-CO2(eq)/year

Emissions profiles are included in **Attachment IV**.

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

Pursuant to District Rule 2201, the 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 (AER) that have occurred at the source, and which have not been used on-site (not applicable).

SSPE1 (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
SSPE Calculator	50,578	19,864	57,129	366,348	4,005,261
ATCs S-1624-200 through '-225 (85 MMBtu/hr SGs)	5 x 4542 = 22,710	5 x 2122 = 10,610	5 x 2606 = 13,030	5 x 23,827 = 119,135	5 x 4095 = 20,475
ATC S-1624-174-2				43,584 (increase)	
SSPE1*	73,288	30,474	70,159	529,067	4,025,736

*SG, steam generator, SSPE1 calculation neglects emissions changes from ATCs for new and modified tanks

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

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site (not applicable).

SSPE2 (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
SSPE1	73,288	30,474	70,159	529,067	4,025,736
S-1624-254	4,542	2,122	2,606	27,550	4,095
S-1624-255	4,542	2,122	2,606	27,550	4,095
S-1624-44	0	0	0	0	-4,747
S-1624-69	0	0	0	0	-4,747
SSPE2	82,372	34,718	75,371	584,167	4,024,432

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}	CO	VOC
Facility emissions pre-project	73,288	30,474	70,159	529,067	4,025,736
Facility emissions – post project	82,372	34,718	75,371	584,167	4,024,432
Major Source Threshold	20,000	140,000	140,000	200,000	20,000
Major Source?	Yes	No	No	Yes	Yes

This source is an existing Major Source for NOx, CO, and VOC and will remain a Major Source for these air contaminants.

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)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Estimated Facility PE before Project Increase	36.6	2012.9	15.2	264.5	35.1	35.1	>100,000*
PSD Major Source Thresholds	250	250	250	250	250	250	100,000
PSD Major Source ? (Y/N)	N	Y	N	Y	N	N	Y

*several steam generators including five 85 MMBtu/hr steam generators

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

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 = PE1 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.

<u>Tanks S-1624-44 and '-69 (to be surrendered)</u>
Tanks '-44 and '-69 are equipped with pressure vacuum relief valves and therefore meet the requirement of current BACT Guideline 7.3.1, Petroleum and Petrochemical Production – Fixed Roof Organic Liquid Storage or Processing Tank, < 5,000 bbl tank capacity (see **Attachment V**).

Therefore BE=PE1.

BE = PE1 = 4,747 lb VOC/year

S-1624-254-0 and '-255-0
Since these are new emissions units, 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 for NOx and VOCs, 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	9,084	50,000	No
VOC	8,190	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

Since this facility is not a Major Source for SOx and PM10, this project does not constitute a Federal Major Modification for these air contaminants.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

The project's combined total emission increases are compared to the Federal Major Modification Thresholds in the following table.

Federal Major Modification Thresholds for Emission Increases			
Pollutant	Total Emissions Increases (lb/yr)	Thresholds (lb/yr)	Federal Major Modification?
NO_x*	9,084	0	Yes
VOC*	8,190	0	Yes

*If there is any emission increases in NO_x or VOC, this project is a Federal Major Modification and no further analysis is required.

Since there is an increase in NO_x and VOC emissions, this project constitutes a Federal Major Modification, and no further analysis is required.

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:

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Greenhouse gases (GHG): CO2, N2O, CH4, HFCs, PFCs, and SF6

The first step of this PSD evaluation consists of determining whether the facility is an existing PSD Major Source or not (See Section VII.C.5 of this document).

In the case the facility is an existing PSD Major Source, the second step of the PSD evaluation is to determine if the project results in a PSD significant increase.

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 major source for PSD. Because the project is not located within 10 km 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. Significance of Project Emission Increase Determination

a. Potential to Emit of attainment/unclassified pollutant for New or Modified Emission Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if total potential to emit from all new and modified units is below this threshold, no futher analysis will be needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)						
	NO2	SO2	CO	PM	PM10	CO2e
Total PE from New and Modified Units	4.5	2.1	27.6	2.6	2.6	79,030
PSD Significant Emission Increase Thresholds	40	40	100	25	15	75,000
PSD Significant Emission Increase?	N	N	N	N	N	Y

As demonstrated above, because the project has a total potential to emit from all new and modified emission units greater than PSD significant emission increase thresholds, further analysis is required to determine if the project has an emission increase greater than the PSD significant emission increase thresholds, see step below.

b. Emission Increase for Each Attainment/Unclassified Pollutant with a Significant Emission Increase vs PSD Significant Emission Increase Thresholds

In this step, the emission increase for each attainment/unclassified pollutant is compared to the PSD significant emission increase thresholds, and if emission increase for each attainment pollutant is below this threshold, no futher analysis is needed.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

The project's combined total emission increases are compared to the PSD significant emission increase thresholds in the following table.

PSD Significant Emission Increase Determination: Emission Increase (tons/year)						
						CO2e
Emission Increases (only)						79,030
PSD Significant Emission Increase Thresholds						75,000
PSD Significant Emission Increase?						Y

As demonstrated in the table above, the project emission increases exceed the PSD significant emission increase thresholds for the following pollutant(s): CO_2e. Therefore further analysis is required to determine if the project has a net emission increase greater than the PSD sigificant emission increase threshold for this (these) specific pollutant(s).

c. Net Emission Increase for Each Attainment/Unclassified Pollutant with a Significant Emission Increase vs PSD Significant Emission Increase Thresholds

The net emission increase needs to be calculated only for the (those) pollutant(s) with a PSD significant emission increase.

All creditable emission increases and decreases at the stationary source occurring within the past five years (including those projects not related to the subject project) are calculated to determine if the project results in a significant net emission increase. In this calculation, only creditable emission decreases and increases are counted:

- Emission changes that resulted in the project being a Federal Major Modification (as defined in Rule 2201) or subject to a major PSD permit are not creditable.
- Emission decreases that resulted in the issuance of emission reduction credits are not creditable.

The creditable increases and decreases in emissions during the five years preceding the expected date of commencement of construction of the proposed project must be calculated.

A detail calculation of the creditable emission increases and decreases, including the proposed project, is included in Section VII.

PSD Significant Emission Increase Determination: Net Emission Increase (tons/year)						
						CO2e
Net Emission Increases						79,030
PSD Significant Emission Increase Thresholds						75,000
PSD Significant Net Emission Increase?						Y

As demonstrated in the table above, the project results in a significant net emission increase for CO2e emissions <u>only</u>. As such, the project is subject to Rule 2410 requirements CO2e only and BACT is required for CO2e.

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 for each pollutant is shown in the table(s) below and reported in the PAS database emissions profile.

The QNEC shall be calculated as follows:

QNEC = (PE2 – BE)/4, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/yr.
BE = Baseline Emissions (per Rule 2201) for each emissions unit, lb/yr.

QNEC (lb/qtr) — S-1624-254 and '-255 each)					
Pollutant	NO_X	SO_X	PM_{10}	CO	VOC
PE2 (lb/yr)	4,542	2,122	2,606	27,550	4,095
BE (lb/yr)	0	0	0	0	0
QNEC	1,136	531	652	6,888	1,024

VIII. Compliance

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 an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*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 of this evaluation, the project authorizes two 85 MMBtu/hr new steam generators each 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.

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 above, this project does constitute a Federal Major Modification for NO_X and VOC emissions. Therefore BACT is triggered for NO_X and VOC for all emissions units in the project for which there is an emission increase.

2. BACT Guideline

Please note that BACT Guideline 1.2.1 [Steam Generator (≥ 5 MMBtu/hr, Oilfield) has been rescinded. A project specific BACT analysis was performed to determine BACT for this project and is provided in **Attachment VI**.

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 VI**), BACT has been satisfied with the following:

NO_X: 5 ppmvd @ 3% O_2

SO_X: Natural gas, LPG and waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2.

PM_{10}: Natural gas, LPG and waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2.
CO: 50 ppmvd @ 3% O_2
VOC: Gaseous fuel

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
SSPE2	82,372	34,718	75,371	584,167	4,024,432
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets calculations required?	Yes	No	Yes	Yes	Yes

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X, VOC, PM10, and CO. 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, determined pursuant to Section 4.8

BE = PE1 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 = HAE

The facility is proposing to install a new emissions unit; therefore BE = 0. Also, there is only one emissions unit associated with this project and there are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

NOx

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

PE2 (NO_X) = 9084 lb/year
BE (NO_X) = 0 lb/year
ICCE = 0 lb/year

The project is a Federal Major Modification and therefore the correct offset ratio for NO_x and VOCs is 1.5:1.

Offsets Required (lb/year) = ([9084 – 0] + 0) x 1.5
= 9,084 x 1.5
= 13,626 lb NO_X/year

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

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
3,407	3,407	3,407	3,407

The quarterly requirement for each steam generator is 3407/2 = 1704 lb NOx/qtr.

The applicant has stated that the facility plans to use ERC certificates listed in the following table which have been reserved for the quantities shown.

Certificate	Q1	Q2	Q3	Q4
C-1141-2	1,632	1,632	1,632	
S-2773-2	454	689	275	487
S-3785-2		1143	538	2,636
S-3788-2			962	
S-3790-2	1,321	227		
Subtotal	3,407	3691	3407	3123
		-284 to Q4*		+284 from Q2*
Total	3,407	3,407	3,407	3407

*Rule 2201 Section 4.13.8: AER for NOx and VOC that occurred from April through November (Q2 and Q3) may be used to offset increases in NOx and VOC during any period of the year.

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

$\underline{PM_{10}}$

PE2 (PM10) = 5212 lb/year
BE (PM10) = 0 lb/year
ICCE = 0 lb/year

The site of reductions occurred at another stationary source greater than 15 miles from the proposed steam generators and therefore the correct offset ratio 1.5:1.

Assuming an offset ratio of 1.5:1, the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([5212 – 0] + 0) x 1.5
= 5,212 x 1.5
= 7,818 lb PM_{10}/year

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

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,955	1,955	1,955	1,955

The quarterly requirement for each steam generator is 1955/2 = 978 lb PM10/qtr.

The applicant has stated that the facility plans to use ERC certificates listed in the following table which have been reserved for the quantities shown.

Certificate	Q1	Q2	Q3	Q4
S-2773-4	90	133	58	96
S-2773-5	1,954	2,649	1,427	2,052
N-684-4	0	0	188	
Subtotal	2,044	2,782	1,673	2,148
	-89 to Q3		+282 from Q1 and Q4	-193 to Q3**
Total	1955	2782	1955	1955

*Rule 2201 Section 4.13.8: AER for PM (equivalent to SOx) that occurred from October through March (Q1 and Q4) may be used to offset increases in PM during any period of the year. PM10 may be offset using SOx at an interpollutant offset ratio of 1.0 tons SOx/ton PM10 (District Draft Policy APR 14XX).

As seen above, the facility has sufficient credits to fully offset the quarterly PM10 emissions increases associated with this project.

<u>VOC</u>

Unit	PE2 – BE (lb/yr)
S-1624-254 and '-255	8,190
S-1624-44 and '-69	- 9,494
Total	-1,304

Offsets will not be required for VOCs.

<u>CO</u>

CO: 55,100 lb/yr

Notwithstanding the above, Section 4.6.1 of Rule 2201 states that emissions offsets are not required for increases in carbon monoxide in attainment areas provided 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. The District performed an Ambient Air Quality Analysis based on emissions from Netting Option #1 which is worst case (discussed later) and determined that this project will not result in or contribute to a violation of an Ambient Air Quality Standard for CO (see **Attachment VII**). Therefore, CO offsets are not required for this project.

The ATCs will include the following offset conditions:

Prior to operating equipment under this Authority to Construct, permittee shall surrender emission reduction credits for the following quantities of emissions: NOx: 1704 lb/quarter and PM10: 978 lb/quarter. Offsets include the applicable offset ratio specified in Section 4.8 of Rule 2201 (as amended 4/21/11). PM10 may be offset using SOx at an interpollutant offset ratio of 1.0 tons SOx/ton PM10 . 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] N

ERC Certificate Numbers S-3786-2, S-3797-2 and 'S-3789-2 (or a certificate split from this certificate) 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] N

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, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

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, this project is an SB 288 or Federal Major Modification. Therefore, public noticing for SB 288 or Federal Major Modification purposes is required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	73,288	82,372	20,000 lb/year	No
SO_X	30,474	34,718	54,750 lb/year	No
PM_{10}	70,159	75,371	29,200 lb/year	No
CO	529,067	584,167	200,000 lb/year	No
VOC	4,025,736	4,024,432	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.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	82,372	73,288	9,084	20,000 lb/year	No
SO_x	34,718	30,474	4,244	20,000 lb/year	No
PM_{10}	75,371	70,159	5,212	20,000 lb/year	No
CO	584,167	529,067	55,100	20,000 lb/year	Yes
VOC	4,024,432	4,025,736	-1,304	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Action

As discussed above, public noticing is required for this project for SB288/Federal Major Modification and SSIPE > 20,000 lb/yr purposes. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission 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:

Sulfur content in the gaseous fuel shall not exceed 1.0 grain per 100 dry standard cubic feet. [District Rules 2201 and 4320] N

Emission rates, except during startup and shutdown shall not exceed: NOx (as NOx): 5 ppmvd @ 3% O2 or 0.0061 lb-NOx/MMBtu. [District Rule 2201, 4305, 4306, and 4320] N

Emission rates shall not exceed any of the following: PM10: 0.0035 lb/MMBtu; CO: 50 ppmvd @ 3% O2 or 0.0370 lb-CO/MMBtu; or VOC: 0.0055 lb/MMBtu. [District Rule 2201] N

Emissions rate of NOx shall not exceed 16.5 lb/day nor 4542 lb/yr. [District Rule 2201] N

E. Compliance Assurance

1. Source Testing

NOx and CO

This units are subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr*. Source testing requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in Section VIII, District Rules 4305, 4306, and 4320 of this evaluation.

PM10

Applicant has provided source test information for a 85 MMBtu/hr natural gas fired steam generator also equipped with a North American Model 4231-85-GLE Ultra Low NOx burner and combusting a gas of similar chemical composition. The unit demonstrated compliance with the proposed emissions factor of 0.0035 lb/MMBtu (**Attachment VII**). The District considers this result as representative and therefore startup and ongoing source testing for PM10 will not be required.

1. Monitoring

Sulfur Monitoring for Rule 4320 Compliance

The following conditions will be included on the ATCs for the steam generators:

PUC quality natural gas is any gaseous fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet, no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet, and at least 80% methane by volume. [District Rule 4320] N

If the steam generator is not fired on PUC-regulated natural gas and compliance is achieved through fuel sulfur content limitations, then the sulfur content of the fuel shall be determined by testing sulfur content at a location after all fuel sources are combined prior to incineration, or by performing mass balance calculations based on monitoring the sulfur content and volume of each fuel source. The sulfur content of the fuel shall be determined using the test methods referenced in this permit. [District Rule 4320] N

When complying with sulfur emission limits by fuel analysis or by a combination of source testing and fuel analysis, permittee shall demonstrate compliance at least annually. [District Rule 4320] N

If the unit is fired on PUC-regulated natural gas, valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts may be used to satisfy the fuel sulfur content analysis, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 4320] N

NOx and CO

As required by *District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in Section VIII, District Rules 4305, 4306, and 4320 of this evaluation.

2. Recordkeeping

As required by *District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3,* *and District Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in Section VIII, *District Rules 4305, 4306, and 4320* of this evaluation.

The following permit condition will be listed on permit as follows:

{2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306, and 4320]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of this Rule requires that an ambient air quality analysis (AAQA) 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. Technical Services Division performed modeling for criteria pollutants CO, NOx, SOx and PM10 (**Attachment VIII**). The results are as follows:

Criteria Pollutant Modeling Results*

Steam Generator	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).

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

G. Compliance Certification

The compliance certification is required for any project, which constitutes a New Major Source or a Federal Major Modification.

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Federal Major Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Sections VIII-Rule 2201-C.1.a and VIII-Rule 2201-C.1.b, this project does constitute a

Federal, therefore this requirement is applicable. Included in **Attachment IX** is the Compliance Certification Statement.

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to install 5 new steam generators. Since the new steam generators will 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

As shown in Section VII C.8 above the project results in a Significant Emissions Increase for GHG. Therefore, Rule 2410 is applicable and public notice (pursuant to District Rule 2201, § 5.5.1 through 5.5.6 and § 5.9.1.1 through 5.9.1.5) and BACT for GHG is required for all associated units that result in a GHG emissions increase.

Below is a listing of the requirements of Rule 2410, and demonstration that compliance with the requirements is expected.

A. Best Available Control Technology (BACT)

GHG BACT analyses for all emission units was performed (see **Attachment X**), and resulted with GHG BACT being satisfied. The results of these analyses are summarized below:

GHG: Equipped with variable frequency drive electrical motors driving the blower and water pump and a convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer)

B. Ambient air quality impact analysis

40 CFR 52.21(k) (as referenced in Rule 2410) requires that applications with significant emission increases would not cause or contribute to a violation of and Federal Ambient air quality standard or any applicable maximum allowable increase over baseline concentration (increment consumption).

EPA's March 2011 guidance titled "PSD and Title V Permitting Guidance for Greenhouse Gases" (pages 47 and 48) states that because there are no ambient air quality standards for GHGs that EPA does not recommend that sources be required to model the impacts of GHG emissions due to a project.

The District concurs with this recommendation. Therefore, no modeling of GHG emission increases is required.

C. Ambient air quality monitoring,

40 CFR 52.21(m) (as referenced in Rule 2410) requires that applications with significant emission increases contain an analysis of air ambient air quality in the area that the project would affect, i.e. ambient air quality monitoring.
EPA's March 2011 guidance titled "PSD and Title V Permitting Guidance for Greenhouse Gases" (pages 47 and 48) states that there is an exemption from ambient air quality monitoring in 40 CFR 52.(i)(5)(iii) for pollutants for which there is not an ambient air quality standard (AAQS), i.e. GHGs. Additionally, notwithstanding the provisions of 40 CFR 52.21 (m)(1)(i) that allows the Administrator to require ambient air monitoring for pollutants for which an AAQS does not exist, EPA does not consider it necessary or appropriate for applicants to perform ambient monitoring of GHGs.

The District concurs with this recommendation. Therefore, no ambient monitoring of GHGs is required.

D. Additional impact analyses, including visibility, soils, vegetation

40 CFR 52.21(o) (as referenced in Rule 2410) requires that applications prepare an analysis on the impairment to visibility, soils, and vegetation that would occur as a result of the proposed modification and the general commercial, residential, industrial, or other growth associated with the project.

EPA's March 2011 guidance titled "PSD and Title V Permitting Guidance for Greenhouse Gases" (pages 47 and 48) states that it is not necessary for applicants to assess impacts due to GHG emission increases as there is no method to quantify project level on visibility, soils, and vegetation. The only modeling techniques available for emission increase several orders of magnitude greater than project level emission increases.

The District concurs with this recommendation. Therefore, no additional impact analysis for visibility, soils, vegetation or other related growth is required.

E. Public noticing requirements

District Rule 2410 requires that the project's preliminary decision undergo a 30-day public notification process prior to issuance of ATC(s). Therefore, notification of the preliminary decision shall be given by the following methods:

The notice shall state the emissions change and the degree of increment consumption that is expected from the proposed project. The notice shall also state the ability for the public to make a request for a public hearing.

A list of entities to receive the notification is included in **Attachment XI**.

Compliance with Rule 2410 is expected.

Rule 2530 Federally Enforceable Potentail to Emit

The purpose of this rule is to restrict the emissions of a stationary source so that the source may elect to be exempt from the requirements of Rule 2520. Pursuant to Rule 2530, since this facility has elected exemption from the requirements of Rule 2520 by ensuring actual emissions from the stationary source in every 12-month periods to not exceed the following: ½ the major source thresholds for NOx, VOCs, CO, and PM_{10}; 50 tons per year SO2; 5 tons per year of a single HAP; 12.5 tons per year of any combination of HAPs; 50 percent of any lesser threshold for a single HAP as the EPA may establish by rule; and 50 percent of the major source threshold for any other regulated air pollutant not listed in Rule 2530.

Rule 4001 New Source Performance Standards

40 CFR Part 60, Subpart Dc applies to Small Industrial-Commercial-Industrial Steam Generators between 10 MMBtu/hr and 100 MMBtu/hr (post-6/9/89 construction, modification or, reconstruction).

The subject steam generators have a rating of 85 MMBtu/hr and are fired on natural/TEOR gas. Subpart Dc has no standards for gas-fired steam generators. Therefore the subject steam generator is not an affected facility and subpart Dc does not apply.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). A condition will be placed on the ATC to ensure compliance with the opacity limit.

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

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.

California Health & Safety Code 41700 – Health Risk Analysis

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 VI**), 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-1624-254 and '-255	0.0per million	No

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

1. 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]
2. The steam generator shall not be closer than 305 m from any receptor.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.
F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM_{10} Emission Factor: 0.005 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%

Excess Air Correction to F Factor = $\dfrac{20.9}{(20.9-3)} = 1.17$

$$GL = \left(\frac{0.0035\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0024\ grain/dscf < 0.1\ grain/dscf$$

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

Rule 4301 Fuel Burning Equipment

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

Section 5.0 gives the requirements of the rule.

A person shall not discharge into the atmosphere combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide at dry standard conditions.
A person shall not build, erect, install or expand any non-mobile fuel burning equipment unit unless the discharge into the atmosphere of contaminants will not and does not exceed any one or more of the following rates:

- 200 pound per hour of sulfur compounds, calculated as sulfur dioxide (SO_2)
- 140 pounds per hour of nitrogen oxides, calculated as nitrogen dioxide (NO_2)

- Ten pounds per hour of combustion contaminants as defined in Rule 1020 and derived from the fuel.

District Rule 4301 Limits			
Unit	**NO_2**	**Total PM**	**SO_2**
S-1624-254 and '-255 (lb/hr)	0.018x 85 = 1.53	0.0035 x 85 = 0.30	0.00285 x 85 = 0.24
Rule Limit (lb/hr)	140	10	200

The particulate emissions from the steam generators will not exceed 0.1 gr/dscf at 12% CO2 or 10 lb/hr. Further, the emissions of SOx and NOx will not exceed 200 lb/hr or 140 lb/hr, respectively.

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

District Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2

The units have a maximum heat input of 85 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4305.

District Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3

The units have a maximum heat input of 85 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4306 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4306.

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

This rule limits NOx, CO, SO_2 and PM_{10} emissions from boilers, steam generators and process heaters rated greater than 5 MMBtu/hr. This rule also provides a compliance option of payment of fees in proportion to the actual amount of NOx emitted over the previous year.

The units in this project are all rated at greater than 5 MMBtu/hr heat input and are subject to this rule.

Section 5.1 NOx Emission Limits

Section 5.1 states that an operator of a unit(s) subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

5.1.1 Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or
5.1.2 Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or
5.1.3 Comply with the applicable Low-use Unit requirements of Section 5.5.

Section 5.2.1 states that on and after the indicated Compliance Deadline, units shall not be operated in a manner which exceeds the applicable NOx limit specified in Table 1 of this rule, shown below. On and after October 1, 2008, units shall not be operated in a manner to which exceeds a carbon dioxide (CO) emissions limit of 400 ppmv.

Rule 4320 Emissions Limits			
Category	**Operated on gaseous fuel**		
	NO_X Limit	Authority to Construct	Compliance Deadline
2. Units with a total rated heat input >20.0 MMBtu/hr	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	July 1, 2009	July 1, 2010
	b) Staged Enhanced Schedule Initial Limit 9 ppmv or 0.011 lb/MMBtu; and	July 1, 2011	July 1, 2012
	Final Limit 5 ppmv or 0.0062 lb/MMBtu	January 1, 2013	January 1, 2014

The proposed NOx and CO limits are 5 and 50 ppmv@3% O2, respectively.

Therefore, compliance with the emissions limits of Section 5.2 of District Rule 4320 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.4 Particulate Matter Control Requirements

Section 5.4.1 states that to limit particulate matter emissions, an operator shall comply with one of the options listed in the rule.

Section 5.4.1.1 provides option for the operator to comply with the rule by firing the unit exclusively on PUC-quality gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;

Section 5.4.1.2 provides option for the operator to comply with the rule by limiting the fuel sulfur content to no more than five (5) grains of total sulfur per hundred (100) standard cubic feet.

Section 5.4.1.3 provides option for the operator to comply with the rule by installing and properly operating an emissions control system that reduces SO2 emissions by at least 95% by weight; or limit exhaust SO2 to less than or equal to 9 ppmv corrected to 3 % O2.

The steam generators will be fired on natural gas containing no more than 1 gr S/100 scf. Therefore, compliance with this section of the rule is expected.

Section 5.5 Low Use

Section 5.5 requires that units limited to less than or equal to 1.8 billion Btu per calendar year heat input pursuant to a District Permit to Operate Tune the unit at least twice per calendar year, or if the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown; or operate the unit in a manner that maintains exhaust oxygen concentrations at less than or equal to 3.00 percent by volume on a dry basis.

The subject steam generators are not low use units and therefore the requirements of Section 5.5 do not apply.

Section 5.6, Startup and Shutdown Provisions

Applicable emissions limits are not required during startup and shutdown provided the duration of each start-up or each shutdown shall not exceed two hours, the emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown or operator has submitted an application for a Permit to Operate condition to allow more than two hours for each start-up or each shutdown provided the operator meets all of the conditions specified in Sections 5.6.3.1 through 5.6.3.3. A startup emissions limit for NOx (DEL) has been derived assuming 4 hr combined startup and shutdown times.

Section 5.7 Monitoring Provisions

Section 5.7.1 requires that permit units subject to District Rule 4320, Section 5.2 shall either install or maintain an operational APCO approved Continuous Emission Monitoring System (CEMS) for NO_X, CO and O_2, or implement an APCO-approved alternate monitoring.

E&B has proposed to implement Alternate Monitoring Scheme A (pursuant to District Policy SSP-1105), which requires periodic monitoring of NO_X, CO, and O_2 concentrations at least once a month using a portable analyzer. The following conditions will be placed in the permits to ensure compliance with the requirements of this alternate monitoring plan:

{2395} The permittee shall monitor and record the stack concentration of NOX, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. 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 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320] N

If either the NOx or CO concentrations corrected to 3%, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then 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 4102, 4305, 4306 and 4320] N

All NOx, CO, and O2 emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The NOx, CO, and O2 analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute sample period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive minute period. [District Rules 4102, 4305, 4306 and 4320] N

The permittee shall maintain records of: (1) the date and time of NOx, CO and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320] N

Section 5.7.6.1 requires that operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit To Operate. Sulfur analysis shall be performed in accordance with the test methods in Section 6.2. The following conditions will be placed in the ATCs for compliance with this rule requirement:

If the steam generator is not fired on PUC-regulated natural gas and compliance is achieved through fuel sulfur content limitations, then the sulfur content of the fuel shall be determined by testing sulfur content at a location after all fuel sources are combined prior to incineration, or by performing mass balance calculations based on monitoring the sulfur content and volume of each fuel source. The sulfur content of the fuel shall be determined using the test methods referenced in this permit. [District Rule 4320] N

When complying with sulfur emission limits by fuel analysis or by a combination of source testing and fuel analysis, permittee shall demonstrate compliance at least annually. [District Rule 4320] N

If the unit is fired on PUC-regulated natural gas, valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts may be used to satisfy the fuel sulfur content analysis, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 4320] N

Section 5.8 Compliance Determination

Section 5.8.1 requires that the operator of any unit have the option of complying with either the applicable heat input (lb/MMBtu), emission limits or the concentration (ppmv) emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be retained or listed on the permits as follows:

{2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320]

Section 5.8.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permits as follows:

{2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. For the purposes of permittee-performed alternate monitoring, emissions measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

Section 5.8.4 requires that for emissions monitoring pursuant to Sections 5.7.1 and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following previously listed permit condition will be on the permits as follows:

{2937} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

{2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

Section 6.1 Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. Therefore, the following permit condition will be listed on the permit as follows:

All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306, 4320 and 40 CFR 60.48c(i)]

Section 6.2, Test Methods

Section 6.2 identifies test methods to be used when determining compliance with the rule. The following conditions will be listed on the permits:

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

The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities – EPA Method 2; Stack gas moisture content – EPA Method 4; SOx – EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content – EPA Method 11 or 15; and fuel hhv (MMBtu) –ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 4305, 4306 and 4320]

Section 6.3, Compliance Testing

Section 6.3.1 requires that each unit subject to the requirements in Section 5.2 shall be source tested at least once every 12 months, except if two consecutive annual source tests demonstrate compliance, source testing may be performed every 36 months. If such a source test demonstrates non-compliance, source testing shall revert to every 12 months. The following conditions will be included in the permits:

A source test to demonstrate compliance with NOx and CO emission limits shall be performed within 60 days of startup of this unit. [District Rules 2201 and 4320]

Source testing to measure natural gas-combustion NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306 and 4320]

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

Sections 6.3.2.1 through 6.3.2.7 address the requirements of group testing which is not proposed in this project. Therefore these sections are not applicable.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permits. Therefore, compliance with District Rule 4320 requirements 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. The units will combust gas containing no more than 1 grS/100 scf and therefore compliance 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)

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 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; and
- 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.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus, the District is the Lead Agency for this project.
Project specific impacts on global climate change were evaluated consistent with the adopted District policy – *Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency*. The District's engineering evaluation (this document – **Attachment XII)** demonstrates that the project includes Best Performance Standards (BPS) for each class and category of greenhouse gas emissions unit. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15031 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful Public Notice period, issue ATCs S-1624-254-0 and '-255-0 subject to the permit conditions on the attached draft ATC in **Attachment XIII.**

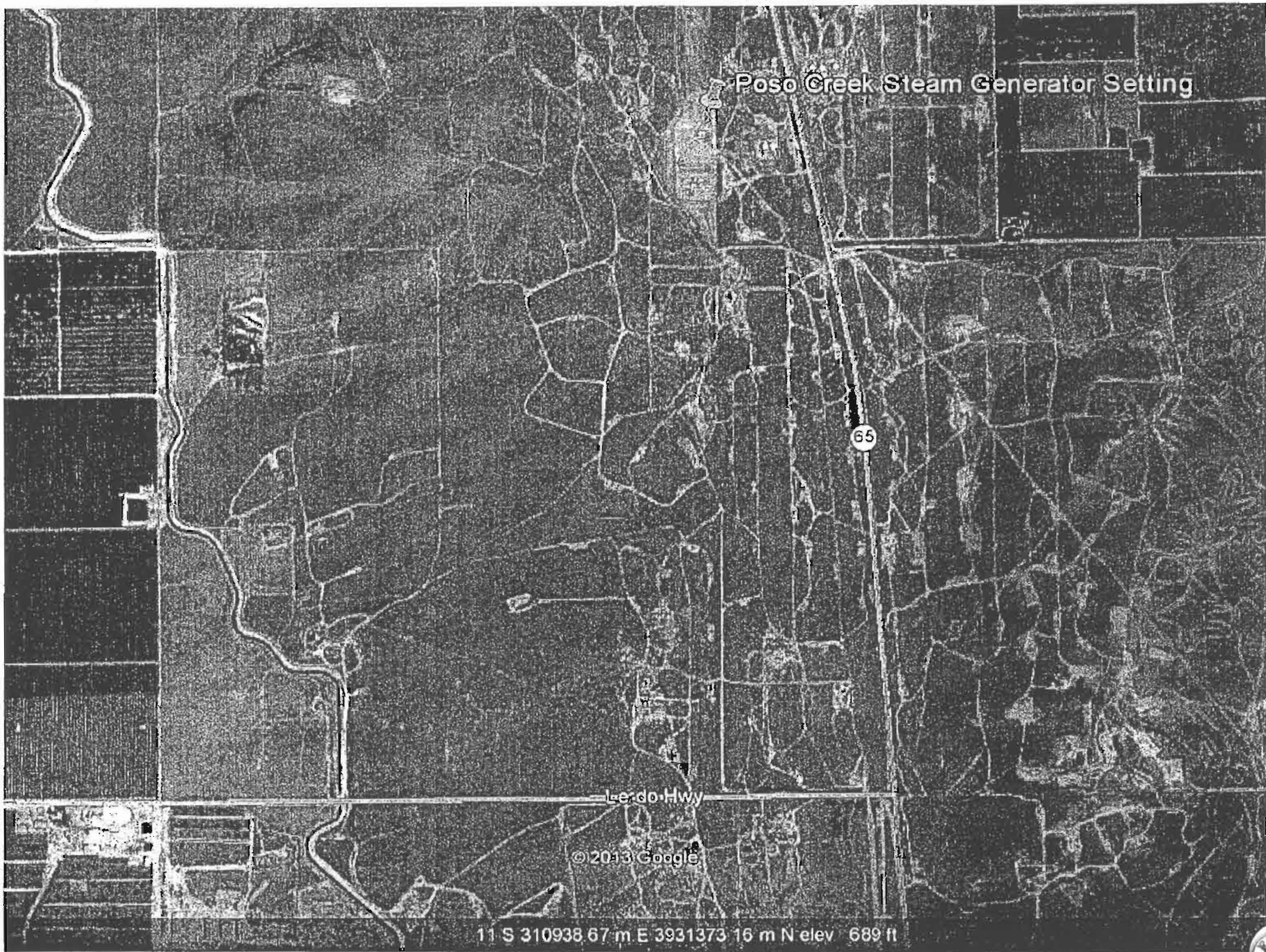
X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-1624-254-0	3020-02-H	85 MMBtu/hr	$1030.00
S-1624-254-0	3020-02-H	85 MMBtu/hr	$1030.00

Attachments

I. Project Location Map
II. Manufacturer's Information on Low NOx burner
III. Tank Emissions Calculations
IV. Emissions Profiles
V. BACT Guideline
VI: BACT Analysis
VII: Source Test Information and Gas Analysis
VIII: HRA and AAQA Modeling
IX: Statewide Compliance Statement
X: GHG BACT Analysis
XI: PSD Entities
XII: BPS Analysis
XIII: Draft ATCs

ATTACHMENT I
Project Location Map


Poso Creek Steam Generator Setting
65
Lerdo Hwy
© 2013 Google
11 S 310938.67 m E 3931373.16 m N elev 689 ft

ATTACHMENT II
Manufacturer's Information on Low NOx Burner

north american

March 20, 2012

Esys
4520 Stine Road, Suite 7
Bakersfield, CA 93313

Attention: Fabio Russoniello, General Manager

Subject: Guarantee of 5 PPM NOx Performance from GLE

Dear Fabio,

Thank you for providing us with this opportunity to confirm that we will indeed guarantee the latest state of the art Ultra Low NOx GLE Burner/Combustion System to achieve <5 ppm NOx performance with FGR on a continuous fully automated basis. We understand that E&B is considering installing (5) of our latest designed Model 4231-85-9X6GGS/X10501 Ultra Low NOx Burners on their new expansion project and that this project will use your mass flow control fuel/air ratio system and PLC based CMS algorithms for field proven performance at this emission level.

To date we have completed thousands of man hours of field testing on both the 62.5 MM and 85 MM Btu/hr GLE Combustion Systems mounted on steam generators in the San Joaquin Valley in order to cement our ability to comfortably make this 5 ppm NOx guarantee. Today we are pleased to offer ESYS our latest version of the product, which has a design basis of 4.0 to 4.4 ppm NOx on an appropriately sized steam generator with the use of FGR. Sustained emission performance below 5 ppm NOx has been achieved on a fully automated field test site for over six months while also demonstrating undetectable levels of CO and trouble free operation. Coupled with the most recent hardware modifications we have also produced some system refinements detailed in our Ultra Low NOx GLE Burner/Combustion System Best Practices document. We are confident that ESYS' installation of this combustion hardware, guided by our best practice approach, combined with your own software will result in repeatable <5 ppm NOx performance.

If you or your customer has any additional questions or concerns relative to our guaranteed performance please do not hesitate to contact us. We look forward to working with you on this project as it develops.

Regards,

John M. Quiel

John M. Quiel
Manager Oil Field Sales
Fives North American Combustion, Inc.

October 28,2011

Ms. Rita Sluga
E & B Natural Resources
1600 Norris Road
Bakersfield, CA 93308

Reference: 5ea. Standard PCL 85MM BTU/hr Steam Generators

Dear Ms. Sluga,

PCL Industrial Services, Inc. is pleased to submit the following proposal to fabricate and install Five (5) 85MM BTU Steam Generators. This proposal excludes the Burner , Fuel Train, VFD's, PLC Panels, instrumentation, conduit, wiring, and feedwater pump which will be purchased by E & B outside our supply. Our scope of supply is as follows:

1-Steam Generator Radiant Scope of Work:

Heating Surface	Approximate 2240 Ft. Sq.
Water Tubes	ASME SA-106-B 3.5″ O.D. Schedule 80 .300″ Thickness ASME Section 1 @ 2000 psi

Refractory

Radiant Cylinder

- Layout and install 304 stainless steel refractory anchors for 3′ walkway from burner drip ledge to target wall. Install 6″ thick 2600° castable refractory.
- Install two 4″ pipes, 6″ long for drain.
- Layout and install 304 stainless steel studs for fiber blanket and folded modules throughout radiant.
- Install 2 layers of 1″ 6-lb fiber blanket followed by one 4″ thick layer of 8-lb 2300° folded fiber modules throughout radiant cylinder excluding 3′ castable walkway.

Burner wall

- Layout and install 304 stainless steel refractory anchors for 3′ burner drip ledge to 3′ walkway. Install 6″ thick 2600° castable refractory.

PCL

- Layout and install 304 stainless steel studs for fiber blanket and modules on burner wall.

Burner wall
- Install fiber blanket and modules on burner wall excluding burner drip ledge.
- Fabricate a burner mounting flange for new burner supplied by others.

Target wall
- Layout and install 304 stainless steel refractory anchors for target wall. Install 6″ thick 2600° castable refractory.

Generator Radiant Internals

Radiant Tubes
- Install sixty-four (64) 3″ schedule 80 tubes 38′ long using SA-106-B pipe.
- Install 3″ XH return bends using SA-234 WPB.
- Radiant piping to have two inlets and two outlets for a Split-Flow design. Both inlets and outlet connections mush penetrate through target wall using sleeves to reinforce the refractory.
- The inlet and out let tubes will have gland type packing rings to seal off any gas.
- Install Mastic 500 high temp internal coating.
- Split Flow radiant for two inlets and two outlets.

Tube Hanger Support
- Install five rows of tube hanger (160) supports using a Two-Tube, three bolt design using 25-12 material.
- Welding of tube hangers should be installed with 309 type welding rod or wire.
- All tube hanger bolts to be 3/4″ 316 stainless steel with heavy hex nuts.

Code Requirements
- All piping and return bends will be fabricated to ASME Section 1 code and registered with the National Board. The design will meet MAWP 2000psi @ 650° deg.
- PCL to perform 10% X-Ray to ASME Section 1.

Shell and Structural Support Steel Fabrication

Radiant Shell and Support Steel Materials
- Fabricate Radiant shell section using 1/4″ plate, A36.
- Fabricate Burner wall with 1/2″ plate, A36.
- Fabricate Target wall with 3/8″ plate, A36.
- Fabricate Radiant support steel with W12 x 40 beam, A36.

Radiant Shell and Support Steel Materials

- Fabricate Radiant with 7 external supports rings with MC-6 x 10.5, A36.
- Fabricate Target wall transition flange with 3″ x 3″ x 3/8″ angle iron, A36.
- Fabricate Burner mounting flange with 1/2″ plate, A36.
- Fabricate Burner support gussets with 1/2″ plate, A36.
- Fabricate 22″ Man-way with 1/4″ plate, A36 with a 316 10ga. stainless steel ring 6″ wide.

Radiant Shell and Support Steel Fabrication

- Fabricate radiant shell using to above material specifications. Radiant dimensions will be approximate 12′ diameter by 40′ long. The shell will be welded both sides.
- Attached seven (7) external supports rings with the above material specifications. All rings should be spaced evenly and continuously welded both sides.
- Fabricate Target wall with the above material specifications. Target wall will be fabricated with a transition flange per the above material specifications. Target wall and transition flange will be welded both sides.
- Fabricate burner wall, burner mounting plate, gusset plates and man-way with the above material specifications. Weld burner mounting plate both sides continuously and attach burner wall by welding both sides.
- Fabricate Radiant support skid with the above material specification. The support skid to have beams on each side of the radiant along with cross beams at each end with three additional cross beams spaced evenly between the end cross beams. The radiant will be attached to the support skid with five saddle type supports. The saddle supports to be fabricated with a web plate and an end plate on each end. The web plates to be constructed with 3/8″ A36 plate and the end plates should be constructed with 3/8″ A36 plate. The saddle supports are to be welded to the radiant support rings and support skid cross beams and end beams.
- All fabrication and welding will meet the requirements of American Welding Society (AWS) D1.1.
- Radiant shell, burner wall, target wall and supports steel will be sandblasted to SP-10 and externally coated with a primer and dunes tan top coat.

2-Econovection Scope of Work:

• Heating Surface	Approximate 20450 Ft. Sq.
• Water Tubes	ASME SA-106-B 3.5″ O.D. Schedule 80 .300″ Thickness ASME Section 1 @ 2000 psi

- The Convection section to be a horizontal flow pyramid type design.
- The water flow to be dual pass design for uniform flow. Gas flow passage shall be arranged to facilitate cleaning by flushing lanes between rows of fin tubes.
- The tubes to be removable through the tube sheets.
- All tube turns to be internal in end cover boxes, but external of tube sheets.
- The convection section tube sheets shall have 4″ of castable refractory. The doors and end cover will have ceramic fiber insulation to maintain a 140 deg F° maximum shell temperature (at ambient temperature 70-degree F°).
- The convection section to be equipped with (1) quick opening door on the top of the convection with 4″ of folded ceramic fiber insulation which will cover the area of the finned tubes. The door will be secured with threaded stud assemblies. Door gasket flanges and joints will be designed to prevent leakage. All bolts to be welded internally to prevent rotation of bolts during nut removal process.
- The transition section between the radiant and the convection will be a new octagon shaped with a larger cross sectional area insulated with 6″ of ceramic fiber on the top and sides. The bottom will be insulated with castable refractory.
- All convection box tubes will be SA-106-B.
- All fittings and return bends will be SA-234 WPB.
- One 42″ diameter by 20′ high free standing vent stack with nine (9) feet of personal protection grating around stack.
- Mating flange for radiant to convection section to be supplied.
- PCL to perform 10% X-Ray to ASME Section 1.
- Convection box, stack, and transition section will be sandblasted to SP-10 and externally coated with a primer and black top coat.

3-Cab Section with Canopy:

- Supply materials for fabrication of an 11' wide by 30' long Cab section.
- Fabricate Cab skid using W12x45 and W10x39.
- Install ¼" diamond plate one top of I-beams.
- Install plate inside of beams to support Blower Motor.
- Fabricate Roof using 3"x3"x1/4" angle iron and 12ga. plate.
- Sandblast and coat dunes tan.

4-Four (4) pass Feed Water Heat Exchangers 2ea:

- Perform ASME Section VIII code calculations and drawings.
- Construct from 4" and 2-1/2" Sch 80 SA-106-B SMLS pipe, SA-234-WPB fittings.
- Each heat exchanger to be equipped with two manual valves for bypass on the hot side.
- Design and Fabricate support frame.
- Coat with Zinc-Oxide primer.
- Insulate both feed water heat exchangers.
- Affix name plate and register with National Board.

5-External Code Piping:

- Supply feed water piping from feed water pump discharge to feed water bypass valves and to convection inlets using 3' SA-106-B pipe schedule 80.
- The feed water inlet line will be equipped with one 3" 1500# gate valve and one 3" 1500# check valve.
- The feed water piping will be supported with field installed pipe supports.
- Both steam discharge lines will be 3" SA-106-B schedule 80 to a single 4" line using SA-106-B schedule 120.
- Steam discharge line will be equipped with one 4" 1500# flanged gate valve and one 4" 1500# flanged check valve.
- Steam discharge line will be equipped with a blow-down flanged connection, but valve is excluded.
- Steam discharge line will be equipped with two (2) 1-1/2" x 4" Crosby relief valves with vent stacks.
- The steam discharge piping will be supported with field installed pipe supports.
- Insulate feed water piping and steam discharge piping.
- Both feed water piping and steam discharge piping will be equipped with pigging flanges at convection inlet, convection out, radiant inlet and radiant outlet.
- PCL to perform 10% X-Ray to ASME B31.1.

6-Horizontal Steam Separators 2ea.

- Perform ASME Section VIII code calculations and drawings.
- Construct from 6" Sch 80 SA-106-B SMLS pipe, SA-234-WPB fittings, 3" 1500# WNRF flanges at each end.
- Coated with Zinc-Oxide primer.
- Affix name plate and register with National Board.

7-Delivery and Field Installation:

- Load out Steam Generators at PCL facility and transport to Lost Hills and Poso locations.
- Offload Steam Generators and set on E & B supplied foundations.
- Assemble Steam Generators complete from feed water pump to steam discharge piping.
- Hydrotest all piping and certify.
- Fabricate and install platform at man-ways in transition section and cab section.
- 5-days for startup assistance.

8-Feed Water Pump Specifiaction for SUPPLY BY OTHERS

217Q-4M National Oilwell Pumps complete with:

- Nickel aluminum bronze liquid ends *2.37S"* tungsten coated plungers Style 8921K packing 316SS valve assemblies with PEEK discs Internal pressure lubricated power end.
- Heavy duty fabricated steel baseplates
- Baldor 200HP, 1800RPM, TEFC, Premium Efficient, IEE841, VFD rated, *3/60/460V* motors
- Commercial *449T* motor bases
- 8GR, SV, 10.30 X *SO.O* V-belt drives with an output speed of346RPM 14GA steel OSHA style belt guards
- Murphy VS-2 vibration switches
- REN RABK crankcase oil regulators.
- Kenco 1SG-36 IS gallon oil tanks and stands.
- Status Flow Model SFV-1S04-F-600 suction stabilizers.
- Status Flow Model SFT-14402-F-600 discharge stabilizers.
- Baird Model 762-7601-2-MP relief valves set @ 1980PSIG
- Units assembled, V -drives aligned and complete units painted desert tan.

ATTACHMENT III
Tank Emissions Calculations

E&B Natural Resources Management, Inc.
LBE Lease

Tank Input Data	
permit number (S-xxxx-xx-xx)	S-1624-44-0
facility tank I.D.	LBE #2
nearest city (1: Bakersfield, 2: Fresno, 3: Stockton)	1
tank ROC vapor pressure (psia)	0.5
liquid bulk storage temperature, Tb (°F)	100
is this a constant-level tank? (yes, no)	No
will flashing losses occur in this tank (only if first-line tank)? (yes, no)	no
breather vent pressure setting range (psi)	0.06
diameter of tank (feet)	15.3
capacity of tank (bbl)	250
conical or dome roof? (c, d)	c
shell height of tank (feet)	8
average liquid height (feet)	5
are the roof and shell the same color? (yes,no)	yes
For roof: color (1:Spec Al, 2:Diff Al, 3:Light, 4:Med, 5:Red, 6:White)	4
condition (1: Good, 2: Poor)	1
------This row only used if shell is different color from roof------	4
------This row only used if shell is different color from roof------	1

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Liquid Input Data	A	B
maximum daily fluid throughput (bbl)		250
maximum annual fluid throughput (bbl)		91,250
------This row only used if flashing losses occur in this tank------		250
------This row only used if flashing losses occur in this tank------		91,250
molecular weight, Mw (lb/lb-mol)		100

Calculated Values	A	B
daily maximum ambient temperature, Tax (°F)		77.65
daily minimum ambient temperature, Tan (°F)		53.15
daily total solar insulation factor, I (Btu/ft^2-day)		1648.9
atmospheric pressure, Pa (psia)		14.47
(psia)	99.0	0.9259
(psia)	88.2	0.6653
water vapor pressure at average liquid surface temperature (Tla), Pva (psia)	93.6	0.7903
roof outage, Hro (feet)		0.1594
vapor space volume, Vv (cubic feet)		580.86
paint factor, alpha		0.68
vapor density, Wv (lb/cubic foot)		0.0084
daily vapor temperature range, delta Tv (degrees Rankine)		49.04
vapor space expansion factor, Ke		0.1032

Results	lb/year	lb/day
Standing Storage Loss	184	0.50
Working Loss	4,563	12.50
Flashing Loss	N/A	N/A
Total Uncontrolled Tank VOC Emissions	4,747	13.0

Summary Table	
Permit Number	**S-1624-44-0**
Facility Tank I.D.	**LBE #2**
Tank capacity (bbl)	**250**
Tank diameter (ft)	**15.3**
Tank shell height (ft)	**8**
Conical or Dome Roof	**Conical**
Maximum Daily Fluid Throughput (bbl/day)	**250**
Maximum Annual Fluid Throughput (bbl/year)	**91,250**
Maximum Daily Oil Throughput (bbl/day)	**250**
Maximum Annual Oil Throughput (bbl/year)	**---**
Total Uncontrolled Daily Tank VOC Emissions (lb/day)	**13.0**
Total Uncontrolled Annual Tank VOC Emissions (lb/year)	**4,747**

ATTACHMENT IV
Emissions Profiles

SJVUAPCD
SOUTHERN

Application Emissions

3/24/13
11:55 am

Permit #: S-1624-254-0	**Last Updated**
Facility: E&B NATURAL RESOURCES MGMT	03/24/2013 EDGEHILR

Equipment Pre-Baselined: NO

	NOX	**SOX**	**PM10**	**CO**	**VOC**
Potential to Emit (lb/Yr):	4542.0	2122.0	2606.0	27550.0	4095.0
Daily Emis. Limit (lb/Day)	16.5	5.8	7.1	75.5	11.2
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	1135.0	530.0	651.0	6887.0	1023.0
Q2:	1135.0	530.0	651.0	6887.0	1024.0
Q3:	1136.0	531.0	652.0	6888.0	1024.0
Q4:	1136.0	531.0	652.0	6888.0	1024.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio	1.5		1.5		
Quarterly Offset Amounts (lb/Qtr)					
Q1:	1704.0		978.0		
Q2:	1704.0		978.0		
Q3:	1704.0		978.0		
Q4:	1704.0		978.0		

Application Emissions

Permit #: S-1624-255-0	**Last Updated**
Facility: E&B NATURAL RESOURCES MGMT	03/24/2013 EDGEHILR

Equipment Pre-Baselined: NO

	NOX	**SOX**	**PM10**	**CO**	**VOC**
Potential to Emit (lb/Yr):	4542.0	2122.0	2606.0	27550.0	4095.0
Daily Emis. Limit (lb/Day)	16.5	5.8	7.1	75.5	11.2
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	1135.0	530.0	651.0	6887.0	1023.0
Q2:	1135.0	530.0	651.0	6887.0	1024.0
Q3:	1136.0	531.0	652.0	6888.0	1024.0
Q4:	1136.0	531.0	652.0	6888.0	1024.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio	1.5		1.5		
Quarterly Offset Amounts (lb/Qtr)					
Q1:	1704.0		978.0		
Q2:	1704.0		978.0		
Q3:	1704.0		978.0		
Q4:	1704.0		978.0		

ATTACHMENT V
BACT Guideline

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 7.3.1*

Last Update: 10/1/2002

Petroleum and Petrochemical Production - Fixed Roof Organic Liquid Storage or Processing Tank, < 5,000 bbl Tank capacity **

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	PV-vent set to within 10% of maximum allowable pressure	99% control (Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal).	

** Converted from Determinations 7.1.11 (10/01/02).

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

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT VI
BACT Analysis

Top Down BACT Analysis for the Steam Generator

Oxides of nitrogen (NO_X) are generated from the high temperature combustion of the natural gas fuel. A majority of the NO_X emissions are formed from the high temperature reaction of nitrogen and oxygen in the inlet air. The rest of the NO_X emissions are formed from the reaction of fuel-bound nitrogen with oxygen in the inlet air.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The District adopted District Rule 4320 on October 16, 2008. The NO_X emission limit requirements in District Rule 4320 are lower than the current BACT limits; therefore a project specific BACT analysis will be performed to determine BACT for this project. District Rule 4320 includes a compliance option that limits oilfield steam generators with heat input ratings greater than 20 MMBtu/hr to 7 ppm @ 3% O_2. This emission limit is Achieved in Practice control technology for the BACT analysis. District Rule 4320 also contains an enhanced schedule option that allows applicants additional time to meet the requirements of the rule. The enhanced schedule NO_X emission limit requirement is 5 ppmv @ 3% O_2. Since this is an enhanced option in the rule, it will be considered the Technologically Feasible control technology for the BACT analysis.

The SJVUAPCD BACT Clearinghouse guideline 1.2.1 has been rescinded. Therefore a new BACT analysis is required. The following are possible control technologies:

1) 5 ppmvd @ 3% O_2 with SCR
2) 7 ppmvd @ 3% O_2

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) 5 ppmvd @ 3% O_2 with SCR
2) 7 ppmvd @ 3% O_2

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis is required for technologically feasible control options that are not proposed. The applicant is proposing a NO_X limit of 5 ppmvd @ 3% O_2, the highest rank technology; therefore, a cost effective analysis is not required.

2. BACT Analysis for SO_X Emissions:

Oxides of sulfur (SO_X) emissions occur from the combustion of the sulfur, which is present in the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for SO_X emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

d. Step 4 - Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for SO_X emissions from this oil field steam generator is natural gas fuel with a sulfur content ≤1 gr-S/100 scf. BACT is satisfied.

3. BACT Analysis for PM_{10} Emissions:

Particulate matter (PM_{10}) emissions result from the incomplete combustion of various elements in the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for CO_{10} emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

d. Step 4 - Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM_{10} emissions from this oil field steam generator is natural gas fuel with a sulfur content ≤1 gr-S/100 scf. BACT is satisfied.

4. BACT Analysis for CO Emissions:

Carbon monoxide (CO) emissions are generated from the incomplete combustion of air and fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for CO emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) 50 ppmvd @ 3% O_2

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) 50 ppmvd @ 3% O_2

d. Step 4 - Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for CO emissions from this oil field steam generator is a CO limit of 50ppmvd @ 3% O_2. The applicant has proposed to install an oil field steam generator with a CO limit of 50 ppmvd @ 3% O_2; therefore BACT for CO emissions is satisfied.

5. BACT Analysis for VOC Emissions:

Volatile organic compounds (VOC) emissions are generated from the incomplete combustion of the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for VOC emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Gaseous fuel

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Gaseous fuel

d. Step 4 - Cost effectiveness analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for VOC emissions from this oil field steam generator is gaseous fuel. The applicant has proposed to install an oil field steam generator fired on gaseous fuel; therefore BACT for PM_{10} emissions is satisfied.

ATTACHMENT VII
Source Test Information and Gas Analysis

San Joaquin Valley Air Pollution Control District

Compliance Source Test Report

Nations Petroleum

Lost Hills
Steam Generator No. 1

Prepared by
Aeros Environmental, Inc.

Determination of Concentrations and Emissions of Particulate

Project 291-6229A

Tested February 19 & 20, 2009

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AEROS ENVIRONMENTAL, INC.

Summary Of Results

Nations Petroleum
Lost Hills
Steam Generator No. 1

Project 291-6229A
February 19 & 20, 2009
ATC No. S-4073-65-0

Pollutant	gr/dscf	gr/scf	lb/hr	lb/MMBtu	Permit Limits
Particulate PM-10	0.00080	0.00067	0.103	0.0012	
	0.00112	0.00094	0.223	0.0017	
	0.00095	0.00080	0.171	0.0014	
Mean	**0.00096**	**0.00080**	**0.166**	**0.0014**	**0.0035 lb/MMBtu**
Particulate Total	0.00104	0.00088	0.134	0.0016	
	0.00133	0.00111	0.264	0.0020	
	0.00104	0.00088	0.188	0.0016	
Mean	**0.00114**	**0.00096**	**0.195**	**0.0017**	**N/A**

Comments:

ZALCO LABORATORIES, INC.
4309 Armour Avenue, Bakersfield, CA 93308 (661) 395-0539 FAX (661) 395-3069 www.zalcolabs.com
2186 Eastman Avenue, Suite 103, Ventura, CA 93003 (805) 477-0114 Fax (805) 477-0125

E & B Natural Resources Corp.
34740 Merced Avenue
Bakersfield CA 93308

Laboratory No: 1204011-01
Date Received: 04/02/12
Date Analyzed: 04/02/12

Attention: Greg Youngblood

Sample Description: SEC. 5 FLARE GAS (POSO CREEK)
Sampled: 04/02/2012 @ 09:41 AM by J. Juarez

Chromatographic Analysis, ASTM D-1945-03, ASTM D-3246-11

Constituent:	Result	Units
Hydrogen Sulfide	1.6	ppm
Total Sulfur	0.10	grs S/100 SCF

Chromatographic Analysis, ASTM D-1945-03, ASTM D-3588-98, GPA 2145-09, ASTM D-3246-11

Constituent:	Mole %	Weight %	GPM	GPM Fractions	CHONS%
					Carbon, C
Oxygen	0.221	0.41	(Gallons per		67.81
Nitrogen	1.511	2.43	1000		
			cubic feet)		Hydrogen, H
Carbon Dioxide	4.106	10.38			21.81
Carbon Monoxide	0.000	0.00			
Hydrogen Sulfide	0.000	0.00			Oxygen, O
Methane	94.111	86.70			7.95
Ethane	0.049	0.09			
Propane	0.001	0.00	0.00	(C3....C3) = 0.00	Nitrogen, N
IsoButane	0.001	0.00	0.00		2.43
n-Butane	0.000	0.00	0.00	(C3....C4) = 0.00	
IsoPentane	0.000	0.00	0.00		Sulfur, S
n-Pentane	0.000	0.00	0.00	(C3....C5) = 0.00	0.00
Hexanes	0.000	0.00	0.00	(C3....C6+) = 0.00	
Totals:	100.00	100.00	0.00	0.00	100.00

Flammable Gases:	94.162	
Gas Properties calculated @ STP: degrees F.	60	
Measurement Base Pressure @ STP: psia	14.696	H/C Ratio: 0.32

Gas State	Dry Btu / Cu. Ft	Dry Btu / lb	Wet Btu / Cu. Ft
Gross, Ideal Gas	951.45	20732.81	934.89
Net, Ideal Gas	856.69	18667.73	841.78
Gross, Real Gas	953.40		936.81
Net, Real Gas	858.45		843.52

Relative Gas Density, [Air=1] Ideal:	0.6013
Specific Gravity, [Air=1] Real gas:	0.6022
Real Gas Density, Lb/Cu.Ft.:	0.0460
Specific Volume, Cu.Ft/Lb:	21.7458
Relative Liquid Density @ 60F/60F:	0.3276
Compressibility, 'Z':	0.9979
Fuel kg per kg-mole Molecular wt avg	17.415

"F" Factor, DSCF/MMBtu @ 60F	8542.5	9487.5
"F" Factor, DSCF/MMBtu @ 68F	8672.6	9632.0
"F" Factor, DSCF/MMBtu @ 70F	8705.6	9668.6
"FC" Factor, DSCF CO2/MMBtu @ 60F	1034.1	1148.5
"FC" Factor, DSCF CO2/MMBtu @ 68F	1049.9	1166.0

ZALCO LABORATORIES, INC.
Analytical & Consulting Services
4309 Armour Avenue
Bakersfield, California 93308
(661) 395-0539
FAX (661) 395-3069

Nations Petroleum U.S.A. Ltd.
3400 Calloway Drive, Building 100
Bakersfield CA 93312

Attention: Jay Marett

Laboratory No: 0710216-001
Date Received: 10/12/07
Date Analyzed: 10/15/07
Purchase Order:
Test Code: 1635

Sample Description: **LH CVR Compressor, Before the Scrubber**
Sampled: 10/10/2007 @ 11:35 AM by Rick Ogletree

Chromatographic Analysis, ASTM D-1945-81, ASTM D-3588-89, GPA 2145-94

Constituent:	Mole %	Weight %	Gas Liquids, Gallons per 1000 cubic feet	CHONS%
				Carbon, C
Oxygen	1.14	1.74		54.65
Nitrogen	4.02	5.37		
				Hydrogen, H
Carbon Dioxide	14.95	31.38		15.42
Carbon Monoxide	0.00	0.00		
				Oxygen, O
Methane	79.60	60.91		24.56
Ethane	0.25	0.35		
Propane	0.01	0.02	0.00	Nitrogen, N
IsoButane	0.00	0.00	0.00	5.37
n-Butane	0.00	0.00	0.00	
IsoPentane	0.00	0.00	0.00	
n-Pentane	0.00	0.00	0.00	
Hexanes	0.00	0.00	0.00	
Heptanes	0.00	0.00	0.00	
Octanes	0.00	0.01	0.00	
Nonanes	0.01	0.03	0.00	
Decanes+	0.03	0.18	0.02	
Totals:	100.00	100.00	0.02	100.00

Gas Properties calculated at STP:	degrees F.	60.000	H/C Ratio:
Measurement Base Pressure at STP:	psia	14.696	0.28212

Gross Btu/Cu.Ft.,	Dry Gas	813.1	Relative Gas Density; {Ideal}	0.72391
Ideal Gross Btu/lb.,	Dry Gas	14683.3	Specific Gravity, [Air=1]	0.72517
Net Btu/Cu.Ft.	Dry Gas	732.3	Real Gas Density, lb./Cu.Ft.	0.05538
Ideal Net Btu/lb.	Dry Gas	13223.1	Specific Volume, Cu.Ft./lb.	18.05785
Gross Btu/Cu.Ft.,	water saturated	811.2	Compressibility, 'z'	0.99768

Robert Cortez, Laboratory Manager

Decanes+ to C12

ATTACHMENT VIII
HRA and AAQA Modeling

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Richard Edgehill, AQE– Permit Services
From:	Ester Davila, SAQS– Technical Services
Date:	March 11, 2013
Facility Name:	E&B Natural Resources
Location:	Section 5 T28S, R27E HOCSS
Application #(s):	S-1624-254-0 thru 255-0
Project #:	S-1130129

A. RMR SUMMARY

RMR Summary				
Categories	**Steam Gen (Unit 254-0)**	**Seam Gen (Unit 255-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	0.04	0.01	0.05	>1
Acute Hazard Index	0.00	0.00	0.00	0.02
Chronic Hazard Index	0.00	0.00	0.00	0.75
Maximum Individual Cancer Risk (10^{-6})	0.00	0.00	0.00	7.46
T-BACT Required?	**No**	**No**		
Special Permit Conditions?	**Yes**	**Yes**		

<u>Proposed Permit Conditions</u>

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

<u>Unit # 254-0 thru 255-0</u>

1. No Unit shall be closer than 305 meters from any receptor
2. 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]

B. RMR REPORT

I. Project Description

Technical Services received a request on March 6, 2013, to perform an Ambient Air Quality Analysis and a Risk Management Review for the installation of 2 new 85 MMBtu/hr steam generators. As part of this project units S-1624-44 and '-69 (tanks) will be cancelled.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total project prioritization score was greater than one, a refined health risk assessment was required. Emissions were calculated using Ventura County emission factors for external combustion of natural gas for the steam generators. Emissions were then input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and the five year concatenated meteorological data for 2005-2009 from Bakersfield to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 254-0 thru 255 each			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	6.1	**Closest Receptor (m)**	305
Stack Diameter. (m)	1.1	**Type of Receptor**	Residential
Stack Exit Velocity (m/s)	17.4	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	388	**Fuel Type**	NG
Burner Rating (MMBtu/hr)	85		

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 53 lb/day CO, 12.2 lb/day NOx, 5.8 lb/day SOx, and 7.1 lb/day PM_{10}. These emissions are for each steam Generator.

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 for each unit. **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. HARP Reports
F. AAQA Reports
G. Facility Summary

ATTACHMENT IX
Statewide Compliance Statement

January 15, 2013

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

Subject: Steam Generator 85G/85H - Compliance Certification

Dear Mr. Scandura:

I hereby certify that all major Stationary Sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in California, which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

Alternative siting analysis is required for any project, which constitutes a New Major Source or a Federal Major Modification.

The current project occurs at existing facilities. The applicant proposes to operate a steam generator to thermally enhance existing wells at the site.

Since the project will provide thermal enhancement 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.

Signature

AIR COMPLIANCE COORDINATOR
Title

ATTACHMENT X
GHG BACT Analysis

BACT Analysis for GHG Emissions

GHG emissions are emitted due to the combustion of fuel and may be emitted indirectly, as a result of electrical power usage.

The USEPA's PSD program issues permits to sources for attainment pollutants and includes GHG as a regulated pollutant. Since the USEPA has not established a national ambient air quality standard for GHG, it is not considered a nonattainment pollutant and is, therefore, considered an attainment pollutant and regulated under the PSD program. Since GHG is regulated under the PSD program the BACT process will follow the steps outlined in the Clean Air Act (CAA) discussed in this section.

The CAA § 169(3) defines BACT as:

> ...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant...

Pursuant to USEPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" the "Top-Down BACT Process" consists of these five basic steps:

1. Identify all available control technologies;
2. Eliminate all technically infeasible options;
3. Rank remaining control technologies by control effectiveness;
4. Evaluate most effective controls and document results;
   a. The energy, environmental, and economic impacts are evaluated starting with the top ranked option.

5. Select BACT based on economic, environmental, and/or energy impacts.

   a. The highest ranked option not eliminated from step 4 is selected as BACT.

Since greenhouse gas is comprised of multiple gases, the objective of this analysis will be to identify control technologies with the lowest emission of a CO_2 equivalent (CO_2e) using the Global Warming Potentials (GWP) identified for the Intergovernmental Panel on Climate Change (IPCC) in the 1996 Second Assessment Report[1].

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[1] The Kyoto Protocol fixed the use of GWP values published by the IPCC in 1996 in its SAR, which remains the internationally recognized values today and are used to calculate GHG reductions in the SJVAPCD Best Performance Standards for oilfield steam generators.

Though it is recognized that reductions in GHG from fossil fuel fired equipment will result in reductions of other criteria pollutants, as the products of combustion, evaluation of GHG control measures will not include the effect on other criteria pollutants except in cases where an increase in criteria pollutants may be expected as a consequence of the proposed measure (e.g. elimination of FGR which would reduce the fuel demand for a steam generator but with the consequence of increasing NO_X emissions, that is a precursor to ozone, which the SJVAPCD is in extreme non-attainment for).

Step 1 - Identify All Possible Control Technologies

<u>When fired on >50% PUC-quality natural gas, commercial propane, and/or LPG:</u>

- A convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by the manufacturer) or a manufacturer's overall thermal efficiency rating of 88% – Achieved in Practice
- Variable frequency drive high efficiency electrical motors driving the blower and water pump – Achieved in Practice
- Additional economizer – Technologically Feasible
- Reduced FGR rate and SCR – Technologically Feasible

<u>When fired on <50% PUC-quality natural gas, commercial propane, and/or LPG:</u>

- Split flow dual pass water feed configuration, a convection section having at least 128 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by the manufacturer) and at least six inches of castable refractory or a manufacturer's overall thermal efficiency rating of at least 85% – Achieved in Practice
- Variable frequency drive high efficiency electrical motors driving the blower and water pump – Achieved in Practice
- Additional economizer – Technologically Feasible
- Reduced FGR rate and SCR – Technologically Feasible

Step 2 - Eliminate Technologically Infeasible Options

- Additional economizer – Technologically Feasible

  Additional waste-heat can be transferred from the exhaust gasses to the steam by installing an extra economizer, further increasing the thermal efficiency of the steam generator.

  Economizers are useful in steam generators that produce a higher quality and lower volume steam. With purified, de-ionized highly filtered water, high quality steam is possible. In oilfield operations neither clean nor de-ionized water is available nor is high quality steam used or useful.

An additional economizer will lower the exhaust gas temperature by transferring the heat energy from exhaust gas to produced steam to increase the quality. However, exhaust gas temperatures must be maintained sufficiently high enough to minimize condensation that can result in exhaust stack corrosion; therefore, adding an economizer to a steam generator is technologically infeasible for oilfield applications.

- Reduced FGR rate and SCR – Technologically Feasible

  Flue gas recirculation mixes a portion of the exhaust gas with the oxygen-rich incoming air in the burner's combustion zone. The added exhaust gas absorbs heat from the combustion process, lowering the peak combustion temperature below the threshold where excessive NO_X is formed. Proven FGR technology has been used in steam generators for years to meet the District's standards for low NO_X emissions. While FGR clearly lowers NO_X levels, additional fuel is required to produce the same amount of steam, which reduces the overall thermal efficiency of the unit and creates more GHG emissions per unit of steam output. Therefore, limiting the FGR rate might be a means of reducing GHG emissions.

  While reducing the FGR rate on a steam generator will decrease GHG emissions, it will also increase NO_X emissions. Since maintaining reductions in criteria pollutants, and specifically NO_X for which the SJVAPCD is in extreme non-attainment, the reduction of GHG will not be considered for an increase in NO_X emissions. Any increase in NO_X emissions must be mitigated.

  The only alternative method for reducing NOx emissions might be SCR, which could make a reduction in the FGR rate feasible. SCR reduces NOx emissions without the need for such extensive FGR. However the SCR system itself results in higher exhaust stack resistance and electric power to operate ammonia or urea injection pumps that offset the energy efficiency gains attributed to the reduced FGR requirement. Therefore, this equipment is not technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Since an oilfield steam generator can operate simultaneously with a minimum convection section heat transfer area requirement (or thermal efficiency rating) and variable frequency drive, high efficiency, electric motors driving the blower and water pump, these options will be combined and listed as follows:

<u>When fired on >50% PUC-quality natural gas, commercial propane, and/or LPG:</u>

- Variable frequency drive high efficiency electrical motors driving the blower and water pump; **and,** a convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer) or a manufacturer's overall thermal efficiency rating of 88%

<u>When fired on <50% PUC-quality natural gas, commercial propane, and/or LPG:</u>

- Variable frequency drive high efficiency electrical motors driving the blower and water pump; **and,** split flow dual pass water feed configuration, a convection section having at least 128 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by the manufacturer) and at least six inches of castable refractory or a manufacturer's overall thermal efficiency rating of at least 85%

Since there is only one option remaining for each type of fuel burned, ranking the control technologies isn't necessary.

Step 4 – Evaluate Controls

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, an evaluation of controls is not required.

Step 5 - Select BACT

The following is a summary of the District's BACT determination for CO_2e control:

Pollutant	BACT
CO_2e	Variable frequency drive high efficiency electrical motors driving the blower and water pump; **and,** When Firing On: • PUC quality natural gas, commercial propane, and/or LPG: a convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer) or a manufacturer's overall thermal efficiency rating of 88%; or,

ATTACHMENT XI
PSD Entities

Distribution List

EPA/CARB – ALL PROJECTS

Gerardo C. Rios, Chief
Permits Office
Air Division
U.S. EPA - Region IX
75 Hawthorne St.
San Francisco, CA 94105

Mike Tollstrup, Chief
Project Assessment Branch
Air Resources Board
P O Box 2815
Sacramento, CA 95812-2815

Counties

Lorelei H. Oviatt, AICP
County of Kern
2700 "M" Street, Suite 100
Bakersfield, CA 933301

Federal Land Managers

Email: Tonnie_Cummings@nps.gov – **prefers email notification**

Email – tprocter@fs.fed.us – **prefers email notification**

Indian Governing Bodies

Santa Rosa Rancheria
c/o Tribal Council
PO Box 8
Lemoore, CA 93245

Santa Ynez Tribe
FreddyRomero1959@yahoo.com
Scohen@santaynezchumash.org

Tule Indian Tribe
c/o Tribal Council
186 N. Reservation Road
Porterville, CA 93257

Air Districts

Antelope Valley AQMD
c/o APCO
43301 Division Street, Suite 206
Lancaster, CA 93535

Eastern Kern APCD
c/o APCO
2700 "M" Street, Suite 302
Bakersfield, CA 93301

San Luis Obispo County APCD
c/o APCO
3433 Roberto Court
San Luis Obispo, CA 93401

Santa Barbara County APCD
c/o APCO
260 N. San Antonio Road #A
Santa Barbara, CA 93110-1315

Ventura County APCD
c/o APCO
669 County Square Dr., 2nd Fl.
Ventura, CA 93003

ATTACHMENT XII
BPS Analysis

San Joaquin Valley
Unified Air Pollution Control District

Best Performance Standard (BPS) x.x.xx

Date: 6/24/10

Class	Steam Generators
Category	Oilfield
Best Performance Standard	**Very High Efficiency Steam Generator Design With:** 1. A convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer) or a manufacturer's overall thermal efficiency rating of 88%. **And** 2. Variable frequency drive high efficiency electrical motors driving the blower and water pump.
Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions	13.0%

District Project Number	C-1100391
Evaluating Engineer	Steve Roeder
Lead Engineer	Arnaud Marjollet
Initial Public Notice Date	April 28, 2010
Final Public Notice Date	May 28, 2010
Determination Effective Date	June 24, 2010

ATTACHMENT XIII
Draft ATCS

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-1624-254-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: E&B NATURAL RESOURCES MGMT
MAILING ADDRESS: ATTN: SHAMS HASAN
3000 JAMES ROAD
BAKERSFIELD, CA 93308

LOCATION: HEAVY OIL CENTRAL
CA

SECTION: 5 **TOWNSHIP:** 28S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
85 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH NORTH AMERICAN MODEL MAGNA FLAME GLE ULTRA LOW NOX BURNER AND FLUE GAS RECIRCULATION

CONDITIONS

1. Unit shall not be located closer than 305 meters from any receptor. [District Rule 4102]
2. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]
3. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]
4. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]
5. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]
6. {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]

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

DAVID WARNER, Director of Permit Services

7. This unit shall be equipped with a convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer). [Rule 2410 and Public Resources Code 21000-21177: California Environmental Quality Act]

8. This unit shall be equipped with variable frequency drive high efficiency electrical motors driving the blower and water pump. [Rule 2410 and Public Resources Code 21000-21177: California Environmental Quality Act]

9. Particulate matter emissions shall not exceed 0.1 grain/dscf at operating conditions, nor 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201, 4301, 5.1 and 5.2.3]

10. 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]

11. Sulfur content in the gaseous fuel shall not exceed 1.0 grain per 100 dry standard cubic feet. [District Rules 2201 and 4320]

12. Duration of start-up and shutdown shall not exceed 2 hours each per occurrence. [District Rules 2201, 4305, 4306, and 4320]

13. Emission rates, except during startup and shutdown shall not exceed: NOx (as NOx): 5 ppmvd @ 3% O2 or 0.0061 lb-NOx/MMBtu. [District Rule 2201, 4305, 4306, and 4320]

14. Emission rates shall not exceed any of the following: PM10: 0.0035 lb/MMBtu; CO: 50 ppmvd @ 3% O2 or 0.0370 lb-CO/MMBtu; or VOC: 0.0055 lb/MMBtu. [District Rule 2201]

15. Emissions rate of NOx shall not exceed 16.5 lb/day nor 4542 lb/yr. [District Rule 2201]

16. Permittee shall maintain records of duration of each start-up and shutdown for a period of five years and make such records readily available for District inspection upon request. [District Rule 4320]

17. A source test to demonstrate compliance with NOx and CO emission limits shall be performed within 60 days of startup of this unit. [District Rules 2201 and 4320]

18. Source testing to measure natural gas-combustion NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306 and 4320]

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

20. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]

21. The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201, 4305, 4306, 4320]

22. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320]

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

24. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. 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 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

25. If the NOx or CO concentrations corrected to 3%, as measured by the portable analyzer, exceed the applicable emission limit, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then 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 4102, 4305, 4306 and 4320]

26. All NOx, CO, and O2 emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The NOx, CO, and O2 analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute sample period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive minute period. [District Rules 4102, 4305, 4306 and 4320]

27. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

28. The permittee shall maintain records of: (1) the date and time of NOx, CO and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320]

29. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the PTO, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. For the purposes of permittee-performed alternate monitoring, emissions measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

30. Shorter time periods for demonstration of compliance after startup or re-ignition may be approved by the APCO by submittal of appropriate technical justification upon implementation of this ATC. [District Rule 2201]

31. PUC quality natural gas is any gaseous fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet, no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet, and at least 80% methane by volume. [District Rule 4320]

32. If the steam generator is not fired on PUC-regulated natural gas and compliance is achieved through fuel sulfur content limitations, then the sulfur content of the fuel shall be determined by testing sulfur content at a location after all fuel sources are combined prior to incineration, or by performing mass balance calculations based on monitoring the sulfur content and volume of each fuel source. The sulfur content of the fuel shall be determined using the test methods referenced in this permit. [District Rule 4320]

33. When complying with sulfur emission limits by fuel analysis or by a combination of source testing and fuel analysis, permittee shall demonstrate compliance at least annually. [District Rule 4320]

34. If the unit is fired on PUC-regulated natural gas, valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts may be used to satisfy the fuel sulfur content analysis, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 4320]

35. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

36. Prior to operating equipment under this Authority to Construct, permittee shall surrender emission reduction credits for the following quantities of emissions: NOx: 1704 lb/quarter and PM10: 978 lb/quarter. Offsets include the applicable offset ratio specified in Section 4.8 of Rule 2201 (as amended 4/21/11). PM10 may be offset using SOx at an interpollutant offset ratio of 1.0 tons SOx/ton PM10 . 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]

37. ERC Certificate Numbers C-1141-2, S-2773-2, S-3785-2, S-3787-2, S-3790-2, S-2773-4, and S-2773-5 (or certificates 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]

38. PTOs S-1624-44-1 and '-69-1shall be canceled upon implementation of ATC. [District Rule 2201]

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-1624-255-0 **ISSUANCE DATE:** DRAFT

DRAFT

LEGAL OWNER OR OPERATOR: E&B NATURAL RESOURCES MGMT
MAILING ADDRESS: ATTN: SHAMS HASAN
3000 JAMES ROAD
BAKERSFIELD, CA 93308

LOCATION: HEAVY OIL CENTRAL
CA

SECTION: 5 **TOWNSHIP:** 28S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
85 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH NORTH AMERICAN MODEL MAGNA FLAME GLE ULTRA LOW NOX BURNER AND FLUE GAS RECIRCULATION

CONDITIONS

1. Unit shall not be located closer than 305 meters from any receptor. [District Rule 4102]
2. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]
3. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]
4. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]
5. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]
6. {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]

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

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DAVID WARNER, Director of Permit Services

S-1624-255-0 : Apr 22 2013 8:30AM – EDGEHILR : Joint Inspection NOT Required

7. This unit shall be equipped with a convection section with at least 235 square feet of heat transfer surface area per MMBtu/hr of maximum rated heat input (verified by manufacturer). [Rule 2410 and Public Resources Code 21000-21177: California Environmental Quality Act]

8. This unit shall be equipped with variable frequency drive high efficiency electrical motors driving the blower and water pump. [Rule 2410 and Public Resources Code 21000-21177: California Environmental Quality Act]

9. Particulate matter emissions shall not exceed 0.1 grain/dscf at operating conditions, nor 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201, 4301, 5.1 and 5.2.3]

10. 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]

11. Sulfur content in the gaseous fuel shall not exceed 1.0 grain per 100 dry standard cubic feet. [District Rules 2201 and 4320]

12. Duration of start-up and shutdown shall not exceed 2 hours each per occurrence. [District Rules 2201, 4305, 4306, and 4320]

13. Emission rates, except during startup and shutdown shall not exceed: NOx (as NOx): 5 ppmvd @ 3% O2 or 0.0061 lb-NOx/MMBtu. [District Rule 2201, 4305, 4306, and 4320]

14. Emission rates shall not exceed any of the following: PM10: 0.0035 lb/MMBtu; CO: 50 ppmvd @ 3% O2 or 0.0370 lb-CO/MMBtu; or VOC: 0.0055 lb/MMBtu. [District Rule 2201]

15. Emissions rate of NOx shall not exceed 16.5 lb/day nor 4542 lb/yr. [District Rule 2201]

16. Permittee shall maintain records of duration of each start-up and shutdown for a period of five years and make such records readily available for District inspection upon request. [District Rule 4320]

17. A source test to demonstrate compliance with NOx and CO emission limits shall be performed within 60 days of startup of this unit. [District Rules 2201 and 4320]

18. Source testing to measure natural gas-combustion NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306 and 4320]

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

20. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]

21. The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201, 4305, 4306, 4320]

22. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320]

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

24. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. 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 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

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25. If the NOx or CO concentrations corrected to 3%, as measured by the portable analyzer, exceed the applicable emission limit, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then 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 4102, 4305, 4306 and 4320]

26. All NOx, CO, and O2 emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The NOx, CO, and O2 analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute sample period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive minute period. [District Rules 4102, 4305, 4306 and 4320]

27. The permittee shall maintain records of: (1) the date and time of NOx, CO and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320]

28. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the PTO, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. For the purposes of permittee-performed alternate monitoring, emissions measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

29. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

30. Shorter time periods for demonstration of compliance after startup or re-ignition may be approved by the APCO by submittal of appropriate technical justification upon implementation of this ATC. [District Rule 2201]

31. PUC quality natural gas is any gaseous fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet, no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet, and at least 80% methane by volume. [District Rule 4320]

32. If the steam generator is not fired on PUC-regulated natural gas and compliance is achieved through fuel sulfur content limitations, then the sulfur content of the fuel shall be determined by testing sulfur content at a location after all fuel sources are combined prior to incineration, or by performing mass balance calculations based on monitoring the sulfur content and volume of each fuel source. The sulfur content of the fuel shall be determined using the test methods referenced in this permit. [District Rule 4320]

33. When complying with sulfur emission limits by fuel analysis or by a combination of source testing and fuel analysis, permittee shall demonstrate compliance at least annually. [District Rule 4320]

34. If the unit is fired on PUC-regulated natural gas, valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts may be used to satisfy the fuel sulfur content analysis, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 4320]

35. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

36. Prior to operating equipment under this Authority to Construct, permittee shall surrender emission reduction credits for the following quantities of emissions: NOx: 1704 lb/quarter and PM10: 978 lb/quarter. Offsets include the applicable offset ratio specified in Section 4.8 of Rule 2201 (as amended 4/21/11). PM10 may be offset using SOx at an interpollutant offset ratio of 1.0 tons SOx/ton PM10 . 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]

37. ERC Certificate Numbers C-1141-2, S-2773-2, S-3785-2, S-3787-2, S-3790-2, S-2773-4, and S-2773-5 (or certificates 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]

38. PTOs S-1624-44-1 and '-69-1shall be canceled upon implementation of ATC. [District Rule 2201]

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