San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

SEP 27 2013

Ms. Melinda Hicks
Kern Oil & Refining Co
7724 E Panama Lane
Bakersfield, CA 93307

Re: Proposed ATC / Certificate of Conformity (Significant Mod)
District Facility # S-37
Project # 1133043

Dear Ms. Hicks:

Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. The project authorizes a 4.6 MW cogeneration system.

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the Authority to Construct with a Certificate of Conformity. Please submit your comments within the 30-day public comment period, as specified in the enclosed public notice. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Leonard Scandura, Permit Services Manager, at (661) 392-5500.

Thank you for your cooperation in this matter.

Sincerely,

David Warner
Director of Permit Services

DW:RE/st

Enclosures

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

Newspaper notice for publication in Bakersfield Californian and for posting on valleyair.org

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NOTICE OF PRELIMINARY DECISION FOR THE ISSUANCE OF AUTHORITY TO CONSTRUCT AND THE PROPOSED SIGNIFICANT MODIFICATION OF FEDERALLY MANDATED OPERATING PERMIT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Air Pollution Control District solicits public comment on the proposed significant modification of Kern Oil & Refining Co at 7724 E Panama Lane, Bakersfield, California. The project authorizes a 4.6 MW cogeneration system. The project authorizes a 4.6 MW cogeneration system and resulted in an increase in NOx, SOx, PM10, CO, and VOC emissions of 6359 lb/yr, 1970 lb/yr, 4700 lb/yr, 9262 lb/yr, and 1797 lb/yr, respectively.

The District's analysis of the legal and factual basis for this proposed action, project #1133043, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and at any District office. There are no emission increases associated with this proposed action. 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 issuance of this modification. For additional information, please contact the District at (661) 392-5500. Written comments on the proposed initial permit must be submitted by November 1, 2013 to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT, 34946 FLYOVER COURT, BAKERSFIELD, CA 93308.**

San Joaquin Valley Air Pollution Control District
Authority to Construct
Application Review
4.6 MW Cogeneration System

Facility Name:	Kern Oil & Refining Co.	Date:	9/24/13
Mailing Address:	7724 E Panama Lane Bakersfield, CA 93307	Engineer: Lead Engineer:	R Edgehill A Phillips
Contact Person:	Melinda Hicks and Joe Selgrath – EnviroTech Consultants, Inc.		
Telephone:	661-845-0761 (MH) 661-377-0073 x12 (JS)		
Application #(s):	S-37-151-0		
Project #:	1133043		
Deemed Complete:	August 5, 2013		

I. Proposal

Kern Oil & Refining Co. (Kern) has requested an Authority to Construct permit for the installation of a 4.6 MW Solar Centaur 50-T6200S Cogeneration system with gas turbine engine (GTE), duct burner, dry low NOx (DLN) combustors, selective catalytic reduction (SCR) system, oxidation catalyst, and waste heat recovery unit (WHRU).

Installation of the cogeneration system results in an increase in combustion emissions and is a Federal Major Modification. BACT, offsets, and public notice are required.

This modification can be classified as a Title V Significant Modification pursuant to Rule 2520, Section 3.29, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that the project be processed in that manner, the 45-day EPA comment period will be satisfied prior to issuance of the Authority to Construct. Kern must apply to administratively amend the Title V Operating Permit to include the requirements of the ATC issued with this project.

II. Applicable Rules

Rule 1081	Source Sampling (12/16/1993)
Rule 1100	Equipment Breakdown (12/17/1992)
Rule 2201	New and Modified Stationary Source Review Rule (4/21/2011)
Rule 2410	Prevention of Significant Deterioration (6/16/2011)
Rule 2520	Federally Mandated Operating Permits (6/21/2001)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emission Standards for Hazardous Air Pollutants (5/20/2004) – **not applicable** – Kern is not a Major HAPS source
Rule 4101	Visible Emissions (2/17/2005)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92) – **not applicable** - does not apply to gas turbines

Rule 4703 Stationary Gas Turbines (8/17/2006)
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 project is located at 7724 E. Panama Lane, in Bakersfield, California, 93307, in Section 25, Township 30S, Range 28E, Mount Diablo Base and Meridian. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Kern Oil & Refining Co. (Kern) is a crude oil refinery that produces gasoline, diesel and other refined products. The applicant is proposing to install the cogeneration unit to supplement existing power and steam to the facility.

The cogeneration system will generate a maximum of 4.6 MW of power under ISO conditions (59 °F, 60% Relative Humidity, 14.696 psi).

The GTE will be installed in a cogeneration configuration with a Waste Heat Recovery Unit (WHRU). The Cogeneration Unit will generate steam and will be fired on purchased natural gas (PUC quality).

A facility plot plan and process flow diagram are included in **Attachment I**.

V. Equipment Listing

S-37-151-0: 4.6 MW SOLAR CENTAUR MODEL 50-T6200S NATURAL GAS FIRED GAS TURBINE ENGINE WITH DRY LOW NOx COMBUSTOR, INLET AIR FILTER, AIR/LUBE OIL COOLER, 21.2 MMBTU/HR DUCT BURNER SYSTEM, WASTE HEAT RECOVERY UNIT, SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AMMONIA ADDITION SYSTEM AND OXIDATION CATALYST (OR EQUIVALENT)

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] Y

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] Y

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

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] Y

VI. Emission Control Technology Evaluation

The new turbine will be equipped with Solar's version of Dry Low NO_X (DLN) combustors, and will exhaust into a Selective Catalytic Reduction [SCR] system, and a CO and VOC Oxidation catalyst. The cogeneration unit is equipped with a duct burner system that functions to combust supplemental fuel mixed with the exhaust from the turbine to increase the generation of steam.

Emissions from natural gas-fired turbines equipped with SCR systems include CO, NO_X, PM_{10}, $PM_{2.5}$, SO_X, VOC, and NH_3.

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

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

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

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

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X

formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

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

VII. General Calculations

A. Assumptions

S-37-151-0: 4.6 MW Solar Centaur Model 50-T6000S

- The GTE/Duct burner system will be fired on PUC quality natural gas.
- Natural gas F-factor is 8,710 dscf/MMBtu
- Power Output rating of the GTE is 4.6 MW at ISO conditions.
- Startup duration is limited to 2 hours per day
- Shutdown duration is limited to 2 hour per day
- Startup and shut down emissions of NOx are uncontrolled emissions
- Oxidation catalyst is active immediately so that emissions of CO and VOC are controlled emissions
- Ammonia slip is limited to 10 ppm @ 15% O_2

Maximum Heat Input (HHV)		
	Daily Maximum, MMBtu/hr	Annual Average, MMBtu/hr
Gas Turbine	60.6 (40°F)	57.7 (59°F)
Duct Burner	21.2	21.2
Total	**81.8**	**78.9 (full load ISO)**
Daily and Annual	1,963.2 MMBtu/day	691,164 MMBtu/yr

B. Emission Factors

The proposed emission factors for the new cogeneration unit are presented below. All ppmv values are calculated at 15% O_2. Maximum emissions occur during periods of cool ambient temperatures, and Peak Output Power.

Startup and Shutdown Emissions Factor

Emission Factors S-37-151 (Uncontrolled)		
	Gas Turbine/Duct Burner	
	ppmv	lb/MMBtu
Natural Gas Fired Gas Turbine and Duct Burner		
NO_X	17.0[1]	0.0625

1. Manufacturer's data

NOx (lb/MMBtu) = (17 ppmvd)(8710 dscf/MMBtu)(2.59 E-9)(46 lb/lb-mole)
x (20.9/(20.9-15)

= 0.0625 lb/MMBtu

Emission Factors S-37-151 (Controlled)		
	Gas Turbine / Duct Burner	
	ppmvd (@ 15% O_2)	lb/MMBtu
NO_X	2.5[1]	0.0092
CO	6.0[1]	0.0134
VOC (as CH_4)	2.0[1]	0.0026
PM_{10}	---	0.0068[2] (weighted average for Duct Burner and Gas Turbine)
SO_X (as SO_2)	---	0.00285 (District Policy APR 1720)
NH_3	10	0.014

1. BACT Guideline 3.4.3 (Last Update 1/18/2005)
   Example calculation – NOx emissions from the GTE/Duct Burner at 2.5 ppm @ 15% O2.

   NOx (lb/MMBtu) = (2.5 ppmvd)(8710 dscf/MMBtu)(2.59 E-9)
   x (46 lb/lb-mole)(20.9/(20.9-15))
   = 0.0092 lb/MMBtu

2. PM_{10} - Weighted Average of Gas Turbine and Duct Burner
   0.0066 lb/MMBtu - AP-42 Table 3.1-2a – Gas Turbine
   0.0075 lb/MMBtu – AP-42 Table 1.4-1, Boiler < 100 MMBtu/hr – Duct Burner

   Peak = [(0.0066 lb/MMBtu)(60.6 MMBtu/hr)
   + (0.0075)(21.2 MMBtu/hr)]/(60.6 + 21.2)
   = 0.0068 lb/MMBtu

   Avg = [(0.0066 lb/MMBtu)(57.7 MMBtu/hr)
   + (0.0075)(21.2 MMBtu/hr)]/(57.7 + 21.2)
   = 0.0068 lb/MMBtu

Note that applicant has stated that the unit is expected to comply with emissions reflecting the above AP-42 emissions factors for PM_{10} (0.0066 lb PM_{10}/MMBtu gas turbine and 0.0075 lb PM_{10}/MMBtu Duct Burner). This claim is supported by source test data (8-13-13 email).

C. Calculations

1. Pre-Project Potential to Emit (PE1)

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

2. Post Project Potential to Emit (PE2)

The post project potential to emit is shown in the table below.

<u>S-37-151-0: 4.6 MW Solar Centaur Model 50-T6000S</u>

The potential to emit for the GTE/WHRU is calculated as follows, and summarized in the table below:

$PE2_{NOx}$ = (0.0092 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (20 hr/day) + (0.0625 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (4 hr/day)
= 35.5 lb NO_X/day

= (0.0092 lb/MMBtu) ∗ (78.9 MMBtu/hr) ∗ (24 hr/day) ∗ (365 day/year)
= 6,358.7 lb NO_X/year

$PE2_{SOx}$ = (0.00285 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (24 hr/day)
= 5.6 lb SO_X/day

= (0.00285 lb/MMBtu) ∗ (78.9 MMBtu/hr) ∗ (24 hr/day) ∗ (365 day/year)
= 1,970 lb SO_X/year

$PE2_{PM10}$ = (0.0068 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (24 hr/day)
= 13.3 lb PM_{10}/day

= (0.0068 lb/MMBtu) ∗ (78.9 MMBtu/hr) ∗ (24 hr/day) ∗ (365 day/year)
= 4,700 lb PM_{10}/year

$PE2_{CO}$ = (0.0134 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (24 hr/day)

= 26.3 lb CO/day

= (0.0134 lb/MMBtu) ∗ (78.9 MMBtu/hr) ∗ (24 hr/day) ∗ (365 day/year)
= 9,262 lb CO/year

$PE2_{VOC}$ = (0.0026 lb/MMBtu) ∗ (81.8 MMBtu/hr) ∗ (24 hr/day)

= 5.1 lb VOC/day
= (0.0026 lb/MMBtu) ∗ (78.9 MMBtu/hr) ∗ (24 hr/day) ∗ (365 day/year)
= 1,797 lb VOC/year

S-37-151 - Post Project Potential to Emit (PE2)		
	Daily Emissions (lb/day)	Annual Emissions (lb/year)
NO_X	35.5	6,359
SO_X	5.6	1,970
PM_{10}	13.3	4,700
CO	26.3	9,262
VOC	5.1	1,797

Emissions Profiles are included in **Attachment II**.

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

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

The Pre-Project Stationary Source Potential to Emit (SSPE1) is summarized below.

Pre-Project Stationary Source Potential to Emit [SSPE1] (lb/year)*					
	NO_X	SO_X	PM_{10}	CO	VOC
S-37	162,903	93,441	40,581	922,334	241,901

*project 1130397 SSPE2 with ATCs involving changes in VOCs

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

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

The Post Project Stationary Source Potential to Emit (SSPE2) is summarized below.

Post Project Stationary Source Potential to Emit [SSPE2] (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Pre-Project SSPE (SSPE1)	162,903	93,441	40,581	922,334	241,901
ATC S-37-151-0	6,359	1,970	4,700	9,262	1,797
Post Project SSPE (SSPE2)	169,262	95,411	45,281	931,596	243,698

5. Major Source Determination

<u>Rule 2201 Major Source Determination:</u>

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

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

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$*	CO	VOC
Facility emissions pre-project	162,903	93,441	40,581	40,581	922,334	241,901
Facility emissions – post project	169,262	95,411	45,281	45,281	931,596	243,698
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	Yes	No	No	No	Yes	Yes

*assume $PM_{10} = PM_{2.5}$

As seen in the table above, the facility is an existing Major Source for NOx, CO, and VOC.

<u>Rule 2410 Major Source Determination:</u>

The facility or the equipment evaluated under this project is 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	81.5	121.0	46.7	461.2	20.3	20.3	>100,000
PSD Major Source Thresholds	100	100	100	100	100	100	100,000
PSD Major Source ? (Y/N)	N	Y	N	Y	N	N	Y

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)

BE = Pre-project Potential to Emit for:

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

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.23
Since this is a new emissions unit, BE = 0 for all criteria pollutants.

7. SB288 Major Modification

As defined in 40 CFR 51.165, in effect on 12/19/02, a project is a SB288 major modification if the source is a major source, and if the net emission increase, i.e. the sum of the differences between the potential to emit and the actual emissions (AE) for all new and modified emission units in a project, are greater than the values listed in Rule 2201 Table 3-5, the project is a SB288 major modification. This calculation is done on a pollutant by pollutant basis.

As discussed in Section VII.C.5 above, the facility is not an existing Major Source for SOx and PM10 and therefore the project is not a major modification for these air contaminants. For NOx and VOCs, the emission unit with this project does not have a total potential to emit which is greater than Major Modification Thresholds (see Table below). Therefore, the project cannot be a significant increase and the project does not constitute a SB 288 Major Modification.

SB288 Major Modification Thresholds (Existing Major Source)			
Pollutant	Project PE (lb/year)	(lb/year)	SB 288 Major Modification Calculation Required?
NO_X	6,359	50,000	No
VOC	1,797	50,000	No

8. Federal Major Modification Calculation

As discussed in section VII.C.5 above, the facility is not a Major Source for PM_{10} or SOx emissions; therefore, the project does not constitute a Federal Major Modification for PM_{10} emissions.

Rule 2201 section 3.17 states that Federal Major Modifications are the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA. SB 288 Major Modifications are not Federal Major Modifications if they meet the criteria of the "Less-Than-Significant Emissions Increase" exclusion.

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

- To determine the post-project projected actual emissions from existing units, the provisions of 40 CFR 51.165 (a)(1)(xxviii) shall be used.
- To determine the pre-project baseline actual emissions the provisions of 40 CFR 51.165 (a)(1)(xxxv)(A) through (D) shall be used.
- If the project is determined not to be a Federal Major Modification pursuant to the provisions of 40 CFR 51.165 (a)(2)(ii)(B), but there is a reasonable possibility that the project may result in a significant emissions increase, the owner or operator shall comply with all of the provisions of 40 CFR 51.165 (a)(6) and (a)(7).

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

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

<u>Emissions Increase for New Unit (EI_N)</u>

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

$EI_N = PE2_N$

Federal Major Modification Thresholds (Existing Major Source)		
Pollutant	Threshold, lb/year	EI, lb/yr
NO_X	0	6,359
VOC	0	1,797

Since NOx and VOC emissions are greater than the Federal Major Modification Thresholds this project is considered a Federal Major Modification for NOx and VOC emissions.

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

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

- NO_2 (as a primary pollutant)
- SO_2 (as a primary pollutant)
- CO
- PM
- PM10
- Greenhouse gases (GHG): CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6

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.

In the case the facility is NOT an existing PSD Major Source but is an existing source, the second step of the PSD evaluation is to determine if the project, by itself, would be a PSD major source.

In the case the facility is new source, the second step of the PSD evaluation is to determine if this new facility will become a new PSD major Source as a result of the project and if so, to determine which pollutant will result 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	3.2	1.0	4.6	2.4	2.4	40,329*
PSD Significant Emission Increase Thresholds	40	40	100	25	15	75,000
PSD Significant Emission Increase?	N	N	N	N	N	N

*78.9 MMBtu/hr x 8760 hr/yr x 116.7 lb-CO2e/MMBtu = 80,658,839 lb-CO2e/yr

80,658,839 lb-CO2e/yr ÷ 2,000 lb/ton = 40,329 tons-CO2e/year

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

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. The QNEC for the new emissions unit was calculated for each pollutant by dividing annual emissions by 4 quarters/year.

S-37-151

Pollutant	QNEC			
	Annual emissions (lb/year)	divided by	4 quarters/yr =	Quarterly emissions (lb/qtr)
NO_X	6,359	/	4 qtr/year	**1,590**
SOx	1,970	/	4	**493**
PM_{10}	4,700	/	4	**1175**
CO	9,262	/	4	**2316**
VOC	1,797	/	4	**449**

VIII. Compliance

Rule 1081 Source Sampling

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

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance, with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
- 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]
- Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]
- For the purpose of determining compliance with the emissions limits (ppmvd @ 15% O2) during normal operation in this permit, the arithmetic mean of three test runs shall apply, unless two of the three results are above an applicable limit. If two of three runs are above the applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 1081]
- The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and 02 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may

also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, and 40 CFR 60.4400 (1)(i)]

- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
- The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rule 1081]

Rule 1100 Equipment Breakdown

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

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

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 exempted pursuant to Section 4.2, 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 SB288 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 applicant is proposing to install a new cogeneration unit 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}, and VOC since the PEs are greater than 2 lbs/day. BACT is triggered for CO since the

SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

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 emissions units being modified as a result of this project; therefore BACT is not triggered.

b. Federal Major Modification

As discussed in Section VII.C.7 above, this project does constitute a Federal Major Modification for NOx and VOC emissions; therefore BACT is triggered for NOx and VOC emissions for all emissions units in the project for which there is an emission increase. As the proposed new cogeneration unit is the only unit with a potential increase, BACT for NOx and VOC for this unit will be required.

2. BACT Guideline

BACT Guideline 3.4.3, applies to Gas Turbine with Heat Recovery = > 3 MW and = < 10 MW. (See **Attachment III**)

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

NO_X: 2.5 ppmv @15% O_2, based on a three-hour average (Selective Catalytic Reduction or equal)
PM_{10}: Air Inlet Filter, Lube Oil Vent Coalescer, and PUC Regulated Natural Gas Fuel.
VOC: 2.0 ppmv @ 15% O_2, based on a one-hour average
SOx: PUC Regulated Natural Gas or non-PUC gas with no more than 1.0 gr S/100 dscf.
CO: 6 ppmvd @15% O_2 over a 3 hour averaging period (catalytic oxidation or equal).

B. Offsets

1. Offset Applicability

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post Project Stationary Source Potential to Emit (SSPE2) equals to or exceeds the offset threshold levels in Table 4-1 or Rule 2201.

The following table compares the post-project facility-wide annual emissions to offset thresholds to determine if offsets will be required for this project.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post Project SSPE (SSPE2)	169,262	95,411	45,281	931,596	243,698
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	Yes	Yes	No*	Yes

* Pursuant to section 4.6.1, increases in CO emissions are exempt from offsets if the applicant demonstrates to the satisfaction of the APCO that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

2. Quantity of Offsets Required

As seen above the SSPE2 is greater than the offset thresholds for NO_X, VOC, PM_{10}, and SOx; therefore offset calculations will be required for this project.

Per Sections 4.7.1 and 4.7.3, the quantity of offsets in pounds per year for NO_X, SOx, CO, VOC and PM_{10} 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) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$, 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 = Pre-project Potential to Emit for:

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

- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

The facility is an existing Major Source for NOx and VOC. However, since this is a new unit the baseline emissions are equal to 0 for NOx and VOC. There are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

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

BE = 0 lb/year for all pollutants
ICCE = 0 lb/year

Therefore,

Offsets Required (lb/year) = PE2 X DOR

The project is a Federal Major Modification and therefore the correct offset ratio for all pollutants except PM_{10} and SOx is 1.5:1. For PM_{10} and SOx emissions the offset ratio of 1.5 is based on a source of ERCs that occurred from reductions at a site greater than 15 miles from the project. Assuming an offset ratio of 1.5:1, the amount of ERCs that need to be withdrawn are shown in the following table

Offset Required		
Pollutant	PE2, lb/yr	Offsets Required lb/year
NO_X	6,359	9,539
SO_X	1,970	2,955
PM_{10}	4,700	7,050
VOC	1,797	2,696

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total, lb/yr
NOx	2,385	2,385	2,385	2,385	9,540
SOx	739	739	739	739	2,956
PM_{10}	1,763	1,763	1,763	1,763	7,052
VOC	674	674	674	674	2,696

The applicant has stated that the facility plans to use ERC certificates C-1191-2, S-2387-5, S-2649-4, and S-3806-1 to offset the increases in emissions associated with this project. The following quantizes have been reserved for the project:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total, lb/yr
C-1191-2*	2,385	3,736	2,703	716	9,540
S-2387-5	739	739	739	739	2,956
S-2649-4	1,763	1,763	1,763	1,763	7,052
S-3806-1	674	674	674	674	2,696

*transfer 318 from 3rd to 4th and 1,351 from 2nd to 4th

Prior to operating equipment under this Authority to Construct, permittee shall surrender emission reduction credits for the following quantities of emissions: NOx: 2,385 lb/1st quarter, 3,736 lb/ 2nd quarter, 2,703 lb/3rd quarter, 716 lb/4th quarter; SOx: 739 lb/quarter; PM10: 1,763 lb/quarter, and VOC: 674 lb/qtr. 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 . [District Rule 2201 and Public Resources Code 21000-21177: California Environmental Quality Act] Y

ERC Certificate Numbers C-1191-2, S-2387-5, S-2649-4, and S-3806-1 (or certificates split from theses 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] Y

Therefore, sufficient offsets have been provided for the project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB288 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 SB288 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 Sections VII.C.7 and VII.C.8, this project is a Federal Major Modification. Therefore, public noticing for 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 following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/yr)	SSPE2 (lb/yr)	Offset Threshold	Public Notice Required?
NOx	162,903	169,262	20,000 lb/yr	No
SOx	93,441	95,411	200,000 lb/yr	No
PM_{10}	40,581	45,281	20,000 lb/yr	No
CO	922,334	931,596	29,200 lb/yr	No
VOC	241,901	243,698	54,750 lb/yr	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 Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 - SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively.

The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Offset Threshold					
Pollutant	SSPE2 (lb/yr)	SSPE1 (lb/yr)	SSIPE (lb/yr)	Offset Threshold	Public Notice Required?
NOx	169,262	162,903	6,359	20,000 lb/yr	No
SOx	95,411	93,441	1,970	200,000 lb/yr	No
PM_{10}	45,281	40,581	4,700	20,000 lb/yr	No
CO	931,596	922,334	9,262	29,200 lb/yr	No
VOC	243,698	241,901	1,797	54,750 lb/yr	No

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

2. Public Notice Action

As discussed above, public noticing is required for this project for NO_x and VOC emissions triggering a Federal Major Modification. 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)

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

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- Turbine/Duct Burner shall be fired on natural gas. [District Rule 2201]
- A totalizing mass or volumetric fuel flow meter shall be utilized and maintained to calculate the amount of gas combusted based on measured flow meter parameters (fuel pressure and temperature), gas composition, and HHV of the fuel. [District Rules 2201 and 4703]
- Combined turbine and duct burner total heat input shall not exceed 1,963.2 MMBtu/day nor 691,164 MMBtu/year. [District Rule 2201]
- Sulfur content of natural gas in the fuel being combusted shall not exceed 1.0 grains/100 scf. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801]
- Emissions from the cogeneration system, except during periods of startup and shutdown, shall not exceed any of the following limits: 2.5 ppmvd NOx (0.0092 lb/MMBtu) @ 15% O2 referenced as NO2; 6.0 ppmvd CO (0.0134 lb/MMBtu) @ 15% O2; 0.0068 lb-PM_{10}/MMBtu; 2.0 ppmvd VOC (0.0026 lb/MMBtu) referenced as methane. NOx and CO emission limits are based on 3-hour rolling average period. If unit is in either startup, shutdown, or black start mode during any portion of a clock hour, the unit will not be subject to the ppmvd limits for NOx and CO during that clock hour. [District Rules 2201,4201, and 4703]
- Ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24-hour average period. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

Start-up source testing will be required as stated in the following condition:

Source testing to determine compliance with the NOx, CO, and NH3 emission rates (ppmvd @ 15% O2) during normal operation shall be conducted with the GTE and duct burner firing concurrently and with the duct burner fired solely within 90 days of initial startup under this permit and annually thereafter. [District Rule 2201 and 40 CFR 60.4400(a] N

The cogeneration unit is subject to District Rule 4703, *Stationary Gas Turbines,* Source testing requirements, in accordance with this rule, will be discussed in Section VIII of this evaluation.

2. Monitoring

The following monitoring condition is included on the ATC:

The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, O2, and NH3 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703] Y

The cogeneration unit is subject to District Rule 4703, *Stationary Gas Turbines.* Monitoring requirements, in accordance with this rule, will be discussed in Section VIII of this evaluation.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The cogeneration unit is subject to District Rule 4703, *Stationary Gas Turbines.* Recordkeeping requirements, in accordance with this rule, will be discussed in Section VIII of this evaluation.

4. Reporting

The following reporting is requirement is included on the ATC:

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

F. Ambient Air Quality Analysis

Section 4.6.1 of this rule 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, such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Section 4.14.1 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.

The proposed location is in an attainment area for NO_X, CO, and SO_X. The proposed location is in a non-attainment area for PM_{10}. The increase in criteria pollutants due to the proposed equipment will not cause a violation as shown on the table below titled "Criteria pollutant Modeling Results".

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in $\mu g/m^3$

NG Turbine	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[2]	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[3]	Pass[3]
PM2.5	X	X	X	Pass[4]	Pass[4]

*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. The criteria pollutant 1-hour value passed using TIER I NO_2 NAAQS modeling
[2]The project was compared to the 1-hour SO2 National Ambient Air Quality Standard that became effective on August 23, 2010 using the District's approved procedures.
[3]The maximum predicted concentration for emissions of these criteria pollutants from the proposed unit are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[4]The maximum predicted concentration for emissions of these criteria pollutants from the proposed unit are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). The emissions were reviewed using AERMOD View – PM-2.5 NAAQS for PM2.5 24-Hr and PM2.5 Annual.

As shown, the calculated contribution of CO, NO_X. SO_X, PM_{10}, and $PM_{2.5}$, will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard. See **Attachment V** of this document for the AAQA summary sheet.

G. Compliance Certification

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

H. Alternate Siting Analysis

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

Modification; therefore an alternative siting analysis is required.

The current project occurs at an existing facility. The applicant proposes to install a new cogeneration unit that will provide steam and thermal heat to existing operations at the site.

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

Rule 2520 Federally Mandated Operating Permits

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

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

Rule 4001 New Source Performance Standards (NSPS)

The proposed GTE are subject to the requirements of this Rule. The applicable subparts are given below:

- **40 CFR Part 60 Subpart GG** - Standards of Performance for Stationary Gas Turbines
- **40 CFR Part 60 Subpart KKKK** - Standards of Performance for Stationary Combustion Turbines

Detailed discussion on the requirements of each subpart is given below.

40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG.

Subpart KKKK is applicable to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour which commenced construction, modification, or reconstruction after February 18, 2005. Only heat input to the combustion turbine is included when determining if Subpart KKKK is applicable.

The proposed GTE has a maximum heat input of 60.6 MMBtu/hr, therefore the GTE is regulated under 40 CFR Part 60 Subpart KKKK. The unit is exempt from the requirements of 40 CFR Part 60 Subpart GG and no further discussion is required.

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

The requirements of 40 CFR Part 60, Subpart KKKK apply to a stationary combustion turbine with heat input (at peak load) equal to or greater than 10 MMBtu/hr, and that commenced construction, modification or reconstruction after February 18, 2005. This subpart regulates nitrogen oxide (NOx) and sulfur dioxide (SOx) emissions only.

The proposed GTE is rated at >10 MMBtu/hr and will be installed after February 18, 2005. Therefore, the proposed turbine is subject to the requirements of this subpart.

Section 60.4320 *- Standards for Nitrogen Oxides*

Paragraph (a) states that NOx emissions shall not exceed the emission limits specified in Table 1 of this subpart. Table 1 states that modified or reconstructed turbines firing natural gas with a heat input at peak load between 50 MMBtu/hr and 850 MMBtu/hr shall meet a NOx emissions limit of 42 ppmvd @ *15%* O2. This limit is based on 4-hour rolling average or 30-day rolling average as defined in §60.4380(b)(1).

Kern has proposed to meet 2.5 ppmvd NOx @ 15% O2 on three-hour rolling average period in accordance with Rule 4703. Kern is expected to meet this limit. Permit condition enforcing this requirement is provided under Rules 2201 (DELs) and 4703.

Section 60.4330 *- Standards for Sulfur Dioxide*

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following: (1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh) gross output; or (2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. Kern has proposed to burn natural gas that will result in maximum potential sulfur emissions equal to 0.0029 lb-SO_2/MMBtu. The following conditions will ensure compliance with the requirements of this section:

- Sulfur content of natural gas in the fuel being combusted shall not exceed 1.0 grains/100 scf. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801]

Section 60.4335 *- NOx Compliance Demonstration, with Water or Steam injection*

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

Kern is not proposing water or steam injection on this turbine; therefore, the requirements of this section are not applicable.

Section 60.4340 *- NOx Compliance Demonstration, without Water or Steam injection*

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring.

Kern has elected to perform annual source testing as the GTE will not be equipped with CEMS. The following condition will ensure compliance with the requirements of this section:

- Unit shall demonstrate compliance annually with NOx and CO emissions limits. An annual demonstration of compliance with the turbine in operation is not required in any year in which the turbine is not operated at all in the preceding 12 months, in such case, the unit shall be compliance source tested within 60 days of resumption of operation of the turbine. [40 CFR 60.4340 and District Rules 2201 and 4703]

Section 60.4345 *- CEMS Equipment Requirements*

Paragraph (a) states that each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix 8 to this part, except the 7 -day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a ppmvd basis.

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

Paragraph (c) states that each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance

requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.
Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

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

Kern is not proposing to use CEMS on this unit; therefore the requirements of this section are not applicable.

Section 60.4350 *- CEMS Data and Excess NOx Emissions*

Section 60.4350 states that for purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.
(c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed.
(d) If you have installed and certified a NOx diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).
(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
(f) Calculate the hourly average NOx emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Kern is not proposing to operate CEMS in conjunction with this cogeneration unit; therefore the requirements of this section do not apply.

***Section 60.4355** - Parameter Monitoring Plan*

This section describes the continuous monitoring plan required for operators using this method to comply with §60.4335 and §60.4340. The operator is not subject to §40.4335 and has not elected to continuously monitor parameters in lieu of annual source testing. Therefore a parameter monitoring plan is not required:

***Sections 60.4360, 60.4365 and 60.4370** - Monitoring of Fuel Sulfur Content*

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

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located, in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in no continental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, <u>valid purchase contract, tariff sheet or transportation contract for the fuel</u>, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for no continental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for no continental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for no continental areas; or
(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for non-continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

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

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

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

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

The GTE will combust only natural gas a fuel with a limit of 1.0 gr S/100 dscf and records must be kept as stated in the following:

- Sulfur content of natural gas in the fuel being combusted shall not exceed 1.0 grains/100 scf. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801]

- 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. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801] Y

Section 60.4380 *- Excess NOx Emissions and Monitor Downtime*

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Kern is not proposing to monitor surrogate parameters associated with water or steam to fuel ratios to predict NOx emissions. Therefore, the requirements of this paragraph are not applicable.

Paragraph (b) states that for turbines using CEMS:

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

calculated each unit operating day as the average of all hourly NOx emissions rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of ail operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

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

Kern is not operating CEMS or proposing to monitor combustion parameters to document NOx emission controls; therefore the requirements of these paragraphs are not applicable.

Section 60.4385 - Excess *SOx Emissions and Monitoring Downtime*

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

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

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

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

Kern is expected to follow the definitions and procedures specified above for determining periods of excess SOx emissions. Compliance is expected with this section.

Sections 60.4375 and 60.4395 *- Reports Submittal*

Section 60.4375(a) states that for each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

Section 60.4375(b) states that for each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Section 60.4395 states All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period. Kern is proposing to maintain records and submit reports in accordance with the requirements specified in these sections.

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

- The owner or operator shall submit a written report of continuous fuel H_2S monitoring for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess H_2S limits, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the monitor was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [40 CFR 60.4375(a) and 60.4395]

Section 60.4400 *- NOx Performance Testing*

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in *§60.B.* Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Kern will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3) initially and annually thereafter; therefore the following condition will ensure compliance with this section:

- Source testing to determine compliance with the NOx, CO, and NH_3 emission rates (ppmvd @ 15% O2) during normal operation shall be conducted within 90 days of initial startup under this permit and annually thereafter. [District Rules 2201 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit [District Rules 1081 and 4703, and 40 CFR 60.4400 (1)(i)]

***Section 60.4405** -Initial CEMS Relative Accuracy Testing*

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

Kern will not be operating CEMS on this unit; therefore the requirements of this section are not applicable.

***Section 60.4410** - Parameter Monitoring Ranges*

Section 60.4410 sets forth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls. As discussed, Kern is proposing annual source testing and frequent NOx and CO testing with a portable analyzer; therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415 - SOx Performance Testing

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.B. Subsequent SO2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM 05287 (incorporated by reference, see §60.17) for natural gas or ASTM 04177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM 04057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

   (i) For liquid fuels, ASTM 0129, or alternatively 01266, 01552, 02622, 04294, or 05453 (all of which are incorporated by reference, see §60.17); or

   (ii) For gaseous fuels, ASTM 01072, or alternatively 03246, 04084, 04468, 04810, 06228, 06667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Kern is proposing to use PUC quality natural gas as fuel. Therefore no testing is required.

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

Compliance is expected with this Subpart.

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). As the cogeneration unit is fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will ensure compliance with this rule:

- No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (12/17/92), by using EPA method 9. If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)]

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. The following condition will ensure compliance with this rule:

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

California Health & Safety Code 41700 (Health Risk Assessment)

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

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project **(Attachment V)**, 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-37-151	0.006 per million	No

The following special conditions are required:

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] N

Cogeneration unit must be operated at least 228 feet from the property boundary. [District Rule 4102] N

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. As this equipment is fired on gaseous fuel only, compliance is expected.

Rule 4703 Stationary Gas Turbines

The provisions of this rule apply to all stationary gas turbine systems, which are subject to District permitting requirements, and with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0. The subject turbines are subject to District permitting and maximum heat input ratings are above 3 MMBtu/hr; therefore, these turbines are subject to the provisions of this rule.

Section 5.1.3 requires the owner or operator to meet 5 ppmvd NOx @ 15% O2. The applicant has proposed to meet 2.5 ppmvd NOx @ 15% O2.

Section 5.2 requires the owner or operator to meet 200 ppmvd CO @ 15% O2. The applicant has proposed to meet 6 ppmvd CO @ 15% O2. The following condition will be included on the ATC to ensure compliance:

- Emissions from the cogeneration system, except during periods of startup and shutdown, shall not exceed any of the following limits: 2.5 ppmvd NOx (0.0092 lb/MMBtu) @ 15% O2 referenced as NO2; 6.0 ppmvd CO (0.0134 lb/MMBtu) @ 15% O2; 0.0074 lb-PM_{10}/MMBtu; 2.0 ppmvd VOC (0.0026 lb/MMBtu) referenced as methane. NOx and CO emission limits are based on 3-hour rolling average period. If unit is in either startup, shutdown, or black start mode during any portion of a clock hour, the unit will not be subject to the ppmvd limits for NOx and CO during that clock hour. [District Rules 2201,4201, and 4703]

Section 5.3 specifies requirements for transitional periods. The following conditions will be included on the permit to ensure compliance:

- Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703]

- Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rule 4703]

Section 6.2.1 requires the owner or operator to either install, operate, and maintain continuous emissions monitoring equipment for NOx and oxygen or install and maintain APCO-approved alternate monitoring. The applicant has requested the use of an alternate handheld monitor.

The following conditions will be listed on the ATC:

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

- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, O2, and NH_3 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]

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

Section 6.2.4 requires the owner or operator to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Conditions will be included to satisfy compliance with this section.

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [40 CFR 60.108a and District Rules 2201 and 4703]

Section 6.2.6 requires the owner or operator to maintain a daily log that includes local start-up time and stop time, length and reason for reduced load periods, total hours of operation, type and quantity of fuel used.

Section 6.2.8 requires that the operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

The following condition will be included on the ATC:

- Permittee shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up and stop time, length and reason for reduced load periods, total hours of operation, quantity of fuel used, and duration of all start-up and shutdown periods. [District Rule 4703, 6.2.6, 6.2.8]

Section 6.2.9 requires that the operator of a unit subject to Section 5.1.3.3 shall also keep additional records. The turbine is not subject to section 5.1.3.3.

Section 6.2.10 requires that the operator of a unit subject to Section 6.5.2 (public service units) shall identify in the stationary gas turbine system operating log the date and start time and end time that the unit was operated pursuant to Section 6.5.2 and keep a copy of the emergency declaration. The turbine is not subject to section 6.5.2.

6.2.11 The operator of a unit shall keep records of the date, time and duration of each bypass transition period and each primary re-ignition period. The following condition will be included on the ATC:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, duration of each start-up and each shutdown time period; and, on a monthly basis, fuel HHV. [District Rules 2201 and 4703]

6.2.12 The operator of a unit subject to subsection (b) of Table 5-3 (pipeline gas turbine) shall keep records of the date, time and duration of each steady state period and non-steady state period and the quantity of fuel used during each period. The turbine is not subject to this subsection of Table 5-3.

Section 6.3 and 6.3.3 requires the owner or operator to perform annual source test to measure NOx and CO emissions. Source testing conditions will be placed on the permit to satisfy compliance with this section. The following conditions are included on the ATC:

- Source testing to determine compliance with the NOx, CO, and NH_3 emission rates (ppmvd @ 15% O2) during normal operation shall be conducted with the GTE and duct burner firing concurrently and with the duct burner fired solely within 90 days of initial startup under this permit and annually thereafter. [District Rules 2201 and 40 CFR 60.4400(a)]

Section 6.4 identifies various test methods to measure NO_x, CO, O2, HHV and LHV of gaseous fuels. The following conditions are included on the ATC:

- HHV and LHV of the fuel shall be determined by using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703]

- The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, and 40 CFR 60.4400 (1)(i)]

Compliance is expected with this Rule.

Rule 4801 Sulfur Compounds

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

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions for the cogeneration unit are calculated as follows (using worst case emission factors from burning natural gas: 0.0029 lb-SOx/MMBtu):

$$\text{Volume } SO_2 = \frac{nRT}{P}$$

With:

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

$$\frac{0.0029\ lb-SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\ dscf} \times \frac{1\ lb-mol}{64\ lb} \times \frac{10.73\ psi-ft3}{lb-mol-°R} \times \frac{520°R}{14.7\ psi} \times \frac{1{,}000{,}000\ parts}{million} = 2\ \frac{parts}{million}$$

Therefore, compliance with District Rule 4801 requirements is expected and the following conditions will be listed on the permit:

- Sulfur content of natural gas in the fuel being combusted shall not exceed 1.0 grains/100 scf. [40 CFR 60.4330(a)(2), 60.1O2a(g){1){ii), 60.104a, and District Rules 2201 and 4801]

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.

Facility S-37 is subject to ARB's Cap and Trade regulation. Consistent with CCR §15064(h)(3), the District finds that compliance with ARB's Cap and Trade regulation would avoid or substantially lessen the impact of project-specific GHG emissions on global climate change. The District therefore concludes that projects occurring at facilities subject to ARB's Cap and Trade regulation would have a less than significant individual and cumulative 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 § 15301 (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 NSR Public Noticing period and EPA review, issue Authority to Construct S-37-151-0 subject to the permit conditions on the attached draft Authorities to Construct in **Attachment VIII**.

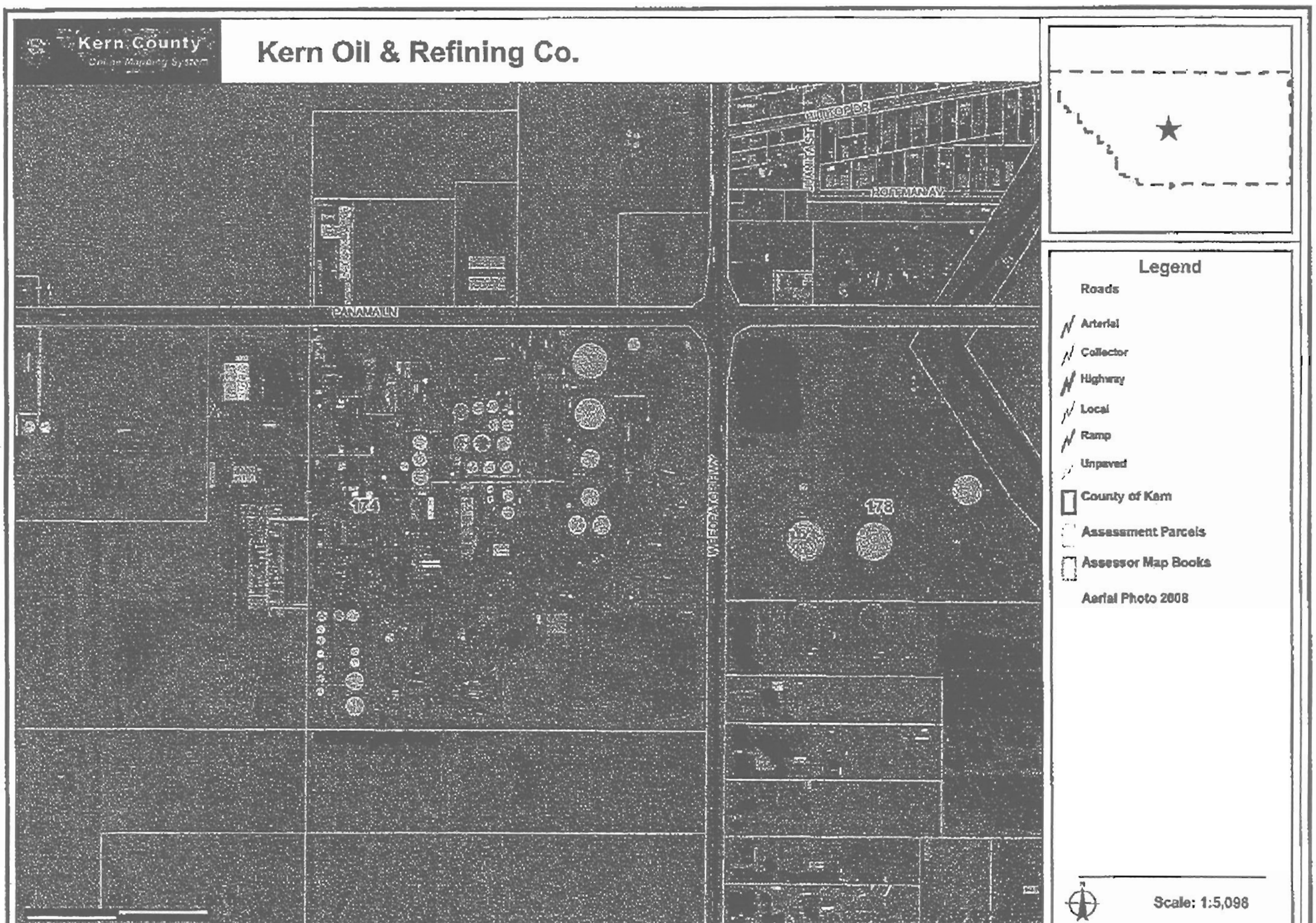
X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-37-151-0	3020-08	4.6 MW	$1,533

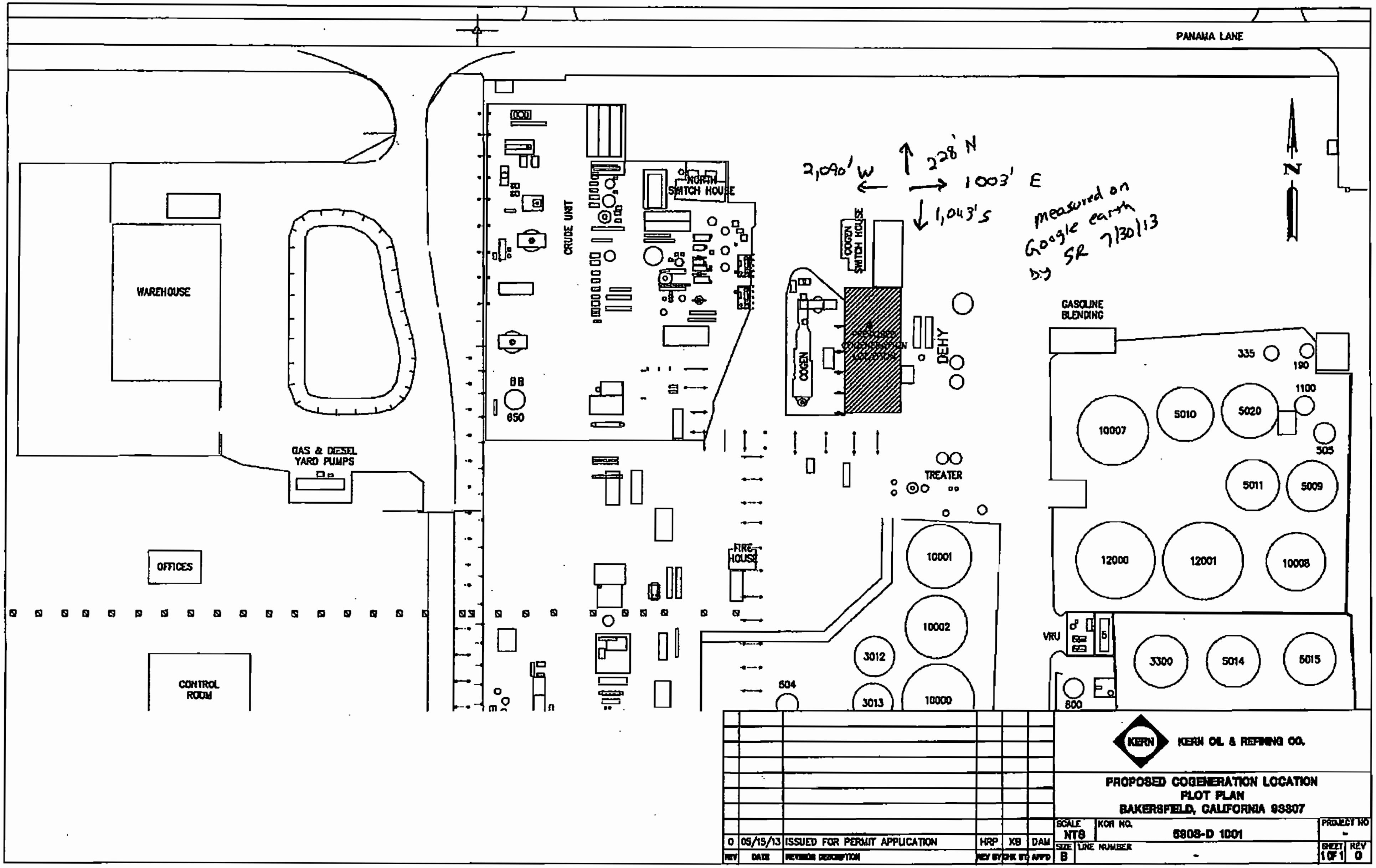
Attachments

I: Project Location Map and Process Diagram
II:: Emission Profiles
III: BACT Guideline
IV: BACT Analysis
V: HRA/AAQA
VI: Statewide Compliance Form
VII: Title V Compliance Certification Form
VIII: Draft ATC

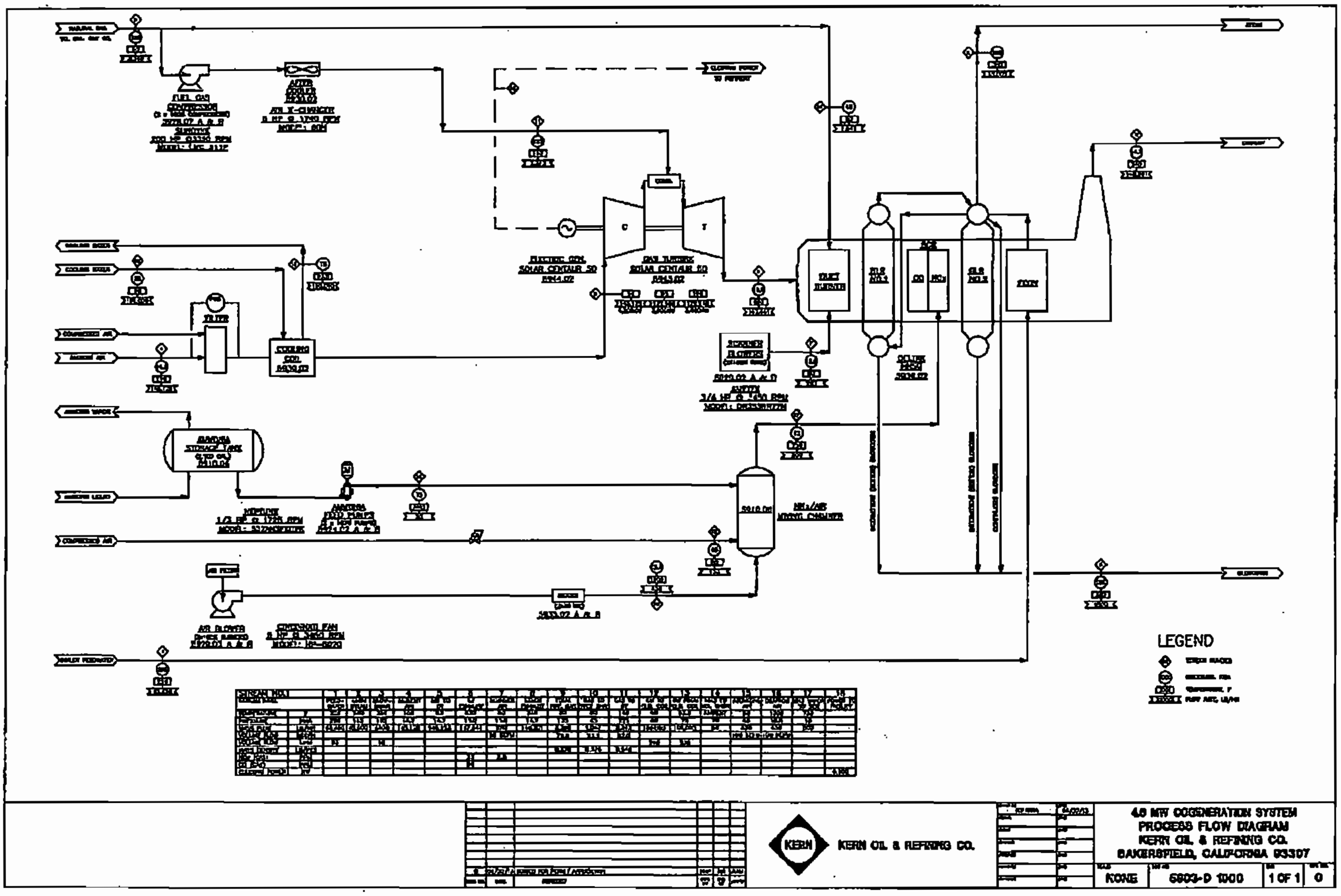
ATTACHMENT I
Project Location Map and Process Diagram



This map is a user generated static output from an Internet mapping site and is for general reference only. Data layers that appear on this map may or may not be accurate, current, or otherwise reliable. THIS MAP IS NOT TO BE USED FOR NAVIGATION.



PANAMA LANE
WAREHOUSE
GAS & DIESEL YARD PUMPS
OFFICES
CONTROL ROOM
CRUDE UNIT
NORTH SWITCH HOUSE
650
FIRE HOUSE
COGEN
COGEN SWITCH HOUSE
DEHY
TREATER
GASOLINE BLENDING
VRU
N
335
190
1100
505
10007
5010
5020
5011
5009
12000
12001
10008
3300
5014
5015
800
10001
10002
10000
3012
3013
504
2,090' W
228' N
1003' E
1,043' S
measured on Google earth by SR 7/30/13
KERN OIL & REFINING CO.
PROPOSED COGENERATION LOCATION
PLOT PLAN
BAKERSFIELD, CALIFORNIA 93307
SCALE NTS
KOR NO. 6808-D 1001
PROJECT NO -
SIZE B
LINE NUMBER -
SHEET 1 OF 1
REV 0
0 05/15/13 ISSUED FOR PERMIT APPLICATION HRP XB DAM
REV DATE REVISION DESCRIPTION REV BY CHK BY APPD


LEGEND
KERN OIL & REFINING CO.
4.5 MW COGENERATION SYSTEM
PROCESS FLOW DIAGRAM
KERN OIL & REFINING CO.
BAKERSFIELD, CALIFORNIA 93307
NONE
6803-D 1000
1 OF 1
0

ATTACHMENT II
Emission Profiles

Application Emissions

Permit #: S-37-151-0	Last Updated
Facility: KERN OIL & REFINING CO.	08/20/2013 EDGEHILR

Equipment Pre-Baselined: NO

	NOX	SOX	PM10	CO	VOC
Potential to Emit (lb/Yr):	6359.0	1970.0	4700.0	9262.0	1797.0
Daily Emis. Limit (lb/Day)	35.5	5.7	13.3	26.3	5.1
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	1589.0	492.0	1175.0	2315.0	449.0
Q2:	1590.0	492.0	1175.0	2315.0	449.0
Q3:	1590.0	493.0	1175.0	2316.0	449.0
Q4:	1590.0	493.0	1175.0	2316.0	450.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio	1.5	1.5	1.5		1.5
Quarterly Offset Amounts (lb/Qtr)					
Q1:	2385.0	739.0	1763.0		674.0
Q2:	2385.0	739.0	1763.0		674.0
Q3:	2385.0	739.0	1763.0		674.0
Q4:	2385.0	739.0	1763.0		674.0

ATTACHMENT III
BACT Guideline

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.3*

Last Update 1/18/2005

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

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

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

***This is a Summary Page for this Class of Source**

ATTACHMENT IV
BACT Analysis
BACT Guideline 3.4.3

1. <u>NO_X Top-Down BACT Analysis:</u>

The emission control devices/technologies and their effect on gas turbine engine (GTE) NO_X emissions are discussed below.

The selective catalytic reduction (SCR) system reduces exhaust stack NO_X emissions.

Step 1 - Identify all control technologies

2.5 ppmv @ 15% O2 based on three-hour average (SCR or equivalent, achieved-in-practice).

Step 2 - Eliminate Technologically Infeasible Options

The above listed technology is technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only identified control technology is 2.5 ppmv @ 15% O2 (SCR or equivalent), which is achieved-in-practice.

Step 4 - Cost Effectiveness Analysis

The only identified control technology is achieved-in-practice and proposed by the applicant. Therefore, calculations for NOx cost effectiveness analysis are not required.

Step 5 - Select BACT

The use of 2.5 ppmv @ 15% O2 emission limit (SCR) satisfies BACT for NOx.

2. <u>SO_X Top-Down BACT Analysis:</u>

Step 1 - Identify all control technologies

PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grS/100 scg or equal (achieved-in-practice).

Step 2 - Eliminate Technologically Infeasible Options

The above listed technology is technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only identified control technology is PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grS/100 scg or equal (achieved-in-practice).

Step 4 - Cost Effectiveness Analysis

The only identified control technology is achieved-in-practice and proposed by the applicant. Therefore, calculations for SOx cost effectiveness analysis are not required.

Step 5 - Select BACT

The use of natural gas with 1.0 gr/100 scf H2S content satisfies BACT for SOx.

3. **PM_{10} Top-Down BACT Analysis:**

Step 1 - Identify all control technologies

Air inlet cooler, lube oil vent coalescer, and natural gas fuel (achieved-in-practice).

Step 2 - Eliminate Technologically Infeasible Options

The above listed technologies are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only identified control technologies are air inlet cooler, lube oil vent coalescer, and natural gas fuel, which are achieved-in-practice.

Step 4 - Cost Effectiveness Analysis

The only identified control technologies are achieved-in-practice and proposed by the applicant. Therefore, calculations for PM10 cost effectiveness analysis are not required.

Step 5 - Select BACT

The use of air inlet cooler, lube oil vent coalescer, and natural gas fuel satisfies BACT for PM10.

4. CO Top-Down BACT Analysis:

The use of catalytic oxidation system reduces exhaust stack CO and VOC emissions.

Step 1 - Identify all control technologies

6.0 ppmv @ 15% O2, based on three-hour average (catalytic oxidation or equal) (Technologically Feasible).

Step 2 - Eliminate Technologically Infeasible Options

The above listed technology is technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only identified control technology is the use of catalytic oxidation system, which is technologically feasible.

Step 4 - Cost Effectiveness Analysis

The only identified control technology is proposed by the applicant. Therefore, calculations for CO cost effectiveness analysis are not required.

Step 5 - Select BACT

The use of catalytic oxidation system satisfies BACT for CO.

5. VOC Top-Down BACT Analysis:

The oxidation catalyst system reduces exhaust stack CO and VOC emissions.

Step 1 - Identify all control technologies

2.0 ppmv @ 15% O2, based on three-hour average (catalytic oxidation or equal) (Technologically Feasible).

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only identified control technology is the use of catalytic oxidation system, which is technologically feasible.

Step 4 - Cost Effectiveness Analysis

The applicant proposed the highest ranked control technology. Therefore, calculations for VOC cost effectiveness analysis are not required.

Step 5 - Select BACT

2.0 ppmv @ 15% O2, based on three-hour average (catalytic oxidation or equal)

ATTACHMENT V
HRA/AAQA

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Steve Roeder – Permit Services
From:	Kyle Melching – Technical Services
Date:	August 1, 2013
Facility Name:	Kern Oil and Refining
Location:	7724 E Panama Ln., Bakersfield
Application #(s):	S-37-151-0
Project #:	S-1133043

A. RMR SUMMARY

Categories	NG Turbine (Unit 151-0)	Project Totals	Facility Totals
Prioritization Score	0.03	0.03	>1
Acute Hazard Index	0.00	0.00	0.75
Chronic Hazard Index	0.00	0.00	0.1
Maximum Individual Cancer Risk	6.04E-09	6.04E-09	7.01E-06
T-BACT Required?	No		
Special Permit Conditions?	Yes		

Proposed Permit Conditions

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

Unit 151-0

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. This unit must be at least 228 feet from the property boundary

B. RMR REPORT

I. Project Description

Technical Services received a revised request on July 30, 2013, to perform an Ambient Air Quality Analysis and a Risk Management Review for the proposed installation of a new 4.6 MW natural gas-fired turbine with a duct burner and ammonia injection.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Emissions were calculated using "NG Internal Combustion - Turbine w/ Catalyst" emission factors. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed units' toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for this proposed units was less than 1; however, the prioritization score for the facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined analysis was required and performed. AERMOD was used with the parameters outlined below and concatenated meteorological data for Bakersfield 2005 – 2009 to determine the maximum dispersion factors.

The following parameters were used for the review:

Analysis Parameters (Unit 151-0)			
Closest Receptor - Business (m)	431	**Closest Receptor – Resident (m)**	452
NG Usage (mmscf/hr)	0.082	**NG Usage (mmscf/yr)**	691.16
Release Height (m)	19.8	**Gas Exit Temperature (K)**	432
Stack Inside Diameter (m)	1.37	**Gas Exit Velocity (m/s)**	7.58

Technical Services also performed modeling for criteria pollutants CO, NOx, Sox, PM_{10}, and $PM_{2.5}$; the following emission rates were used:

	NOx	Sox	CO	PM10	PM2.5
Lbs/hr	0.75	0.24	1.1	0.56	0.56
Lbs/yr	6359	2004	9262	4700	4700

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in μg/m^3

NG Turbine	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[2]	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[3]	Pass[3]
PM2.5	X	X	X	Pass[4]	Pass[4]

*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. The criteria pollutant 1-hour value passed using TIER I NO_2 NAAQS modeling
[2]The project was compared to the 1-hour SO2 National Ambient Air Quality Standard that became effective on August 23, 2010 using the District's approved procedures.
[3]The maximum predicted concentration for emissions of these criteria pollutants from the proposed unit are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[4]The maximum predicted concentration for emissions of these criteria pollutants from the proposed unit are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). The emissions were reviewed using AERMOD View – PM-2.5 NAAQS for PM2.5 24-Hr and PM2.5 Annual.

III. Conclusion

The criteria modeling runs indicate the emissions from the project will not cause or significantly contribute to a violation of a State or National AAQS.

The acute and chronic hazard indices were below 1.0; and the cancer risk associated with the project is **6.04E-09**; which is less than or equal to 1.0 in a million. In accordance with the District's Risk Management Policy, the project is approved **without** Toxic Best Available Control Technology (T-BACT).

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

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Stack Parameter Worksheet
D. Prioritization score w/ toxic emission summary
E. Facility Summary
F. AAQA Summary

Ester Davila

From: Steven Roeder
Sent: Tuesday, July 30, 2013 12:14 PM
To: Ester Davila
Subject: HRA Request for S37, 1133043.docx
Attachments: S37, 1133043.docx

Hi there Ester,

Here is an HRA request for Kern Oil.
It is a Federal Major Modification and triggers public notice and the AAQA.

Therefore I have included the emissions.

Steve R

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

HRA/RMR REQUEST Form

Please send this request to TECHNICAL SERVICES SUPERVISOR

Facility Name:	Kern Oil and Refining	Processing Engineer:	Steve Roeder
Mailing Address:	7724 E. Panama ln	Tec Svces Processing Staff:	
Location:	Bakersfield	Tec Svces Reviewer:	
Contact Name:	Melinda Hicks		
Telephone:	(661) 845-0761		
Application #:	S-37-151-0	Completed Date:	
Project #:	1133043		

Information Required

Please check which information is provided to Tec. Services:

Information ALWAYS Required

- ☒ Receptor Distances
- ☐ Process Rates (hour & annual)
- ☒ Emission Rates (hour & annual)
- ☒ Hours of Operation

Life of Project:

Additional Info Required Based on the Source Category

Oil Facilities / Glass Plant/ Power Plant
Plasma Cutting / Soil Remediation / Concrete Batch

- ☒ Stack Velocity
- ☒ Stack Height
- ☒ Stack temperature
- ☐ MSDS
- ☐ Other (for area sources)

Source of Information

Please check which form is attached to this HRA request (it can be a combination of any of the following):

- ☐ *Supplemental Application Form*
- ☐ *HRA Request - Project Information Form*
- ☒ *Information supplied by the applicant (attached)*

Notification Requirement

Is it obvious that notification is required?			
	NSR (Public Notice)	Yes: ☒	No: ☐
	COC (EPA Notice)	Yes: ☒	No: ☐
	School Notice	Yes: ☐	No: ☒

Please note that in case notification is required, please provide distance to fence line in all four directions

Prevention of Significant Deterioration (PSD)

AQE:

1. Based on the prelim review, is the Project subject to PSD for other pollutant than GHG? Yes: ☐ No: ☒
2. Is the facility a PSD Major Source located within 10 km of a Class I area? Yes: ☐ No: ☒

*If either "Yes" box is checked, please provide all modeling and impact analyses submitted by the applicant to Technical Services. **In this case, the project cannot be deemed complete until Technical Services indicates it is complete.***

Tec Svces:

PSD Major Source located within 10 km of a Class I area AND project impact ≥ 1 $\mu g/m^3$? Yes: ☐ No: ☐

Supervisor Review: Application Complete for PSD Modeling ☐ Date Returned to AQE: __________

Reimbursable Overtime

Has the applicant requested reimbursable overtime processing? Yes: ☐ No: ☐
If YES, please send HRA request to Tech Services before deeming complete

Supervisor's signature: ______________________________

Comments and References:

HRA/RMR REQUEST
PROJECT INFORMATION Form

I. **Project Description:** Cogen: 4.6 MW natural gas turbine with duct burner and ammonia injection

II **Receptor Location(s)**

Receptor Description	Distance From Source
Residence	1483 feet 452m
Business	1414 feet 431m

III. **FENCELINE DISTANCES**

Fenceline Direction	Feet
North	228
West	2090
South	1043
East	1003

IV. **Emission Rate Or Substances to be Modeled**

Process Description	Emission Rates Hourly Rate	Emission Rates Annual Rate
Turbine Exhaust See Below	81.8 MMBtu/hr max	691,164 MMBtu/year max

V. **Project Location** (*Select One*)

☐ Urban – Area of dense population
☒ Rural – Area of sparse population

VI. **Point Sources**

Stack Parameters:

Stack Height (Units)	Rain Cap or Pressure Plate	Inside Diameter (Units)	Gas Exit Velocity (Units)	Exhaust Discharge Direction	Gas Exit Temperature (Units)
65 ft	n	54"	18 ft/sec	up	319F

VII. **Area Sources[1] Parameters**

Release Height[2] (Units)	Length Of Side (Units)

1. An area source is defined as in an area with four equal sides.
2. Release height is defined as the physical height of the source. For example, if a sump has a three meter brim surrounding it. The physical height of the sump is three meters. Height is measured from the ground to the top of the source.

- Emissions

Heat input	[illegible]	MMBtu/hr						
NOx	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	[illegible]	hr =	0.75	lb/hr
SOx	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	0.24	lb/hr
PM10	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	0.56	lb/hr
CO	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	1.10	lb/hr
VOC	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	0.21	lb/hr
CO2E	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	9,571	lb/hr
NH3	[illegible]	lb/MMBtu x	81.8	MMBtu/hr x	1	hr =	1.15	lb/hr
Heat input	[illegible]	MMBtu/hr						
NOx	0.0092	lb/MMBtu x	78.9	MMBtu/hr x	[illegible]	hr/day =	17.4	lb/day
SOx	0.0029	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	5.5	lb/day
PM10	0.0068	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	12.9	lb/day
CO	0.0134	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	25.4	lb/day
VOC	0.0026	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	4.9	lb/day
CO2E	117	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	221,551	lb/day
NH3	0.014	lb/MMBtu x	78.9	MMBtu/hr x	24	hr/day =	26.5	lb/day
NOx	0.0092	lb/MMBtu x	78.9	MMBtu/hr x	[illegible]	hr/year =	6,359	lb/year
SOx	0.0029	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	2,004	lb/year
PM10	0.0068	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	4,700	lb/year
CO	0.0134	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	9,262	lb/year
VOC	0.0026	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	1,797	lb/year
CO2E	117	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	80,866,188	lb/year
NH3	0.014	lb/MMBtu x	78.9	MMBtu/hr x	8,760	hr/year =	9,676	lb/year

Kyle Melching

From: Steven Roeder
Sent: Wednesday, July 31, 2013 3:44 PM
To: Kyle Melching
Subject: RE: Attached Image

Hi Kyle,

Well, they gave me the exhaust flowrate as 17,158 scfm. But the exhaust temp is 319F.
If I convert that into acfm, we have 23,724 acfm.
Thru a 54" stack, the actual velocity becomes **24.9 ft/sec.**

Does that help??

Why would PM2.5 be so high?
We're only talking about 12.9 lb PM10 per day... Lots of things produce more than that, right? The 2.5 fraction makes that number lower, right?

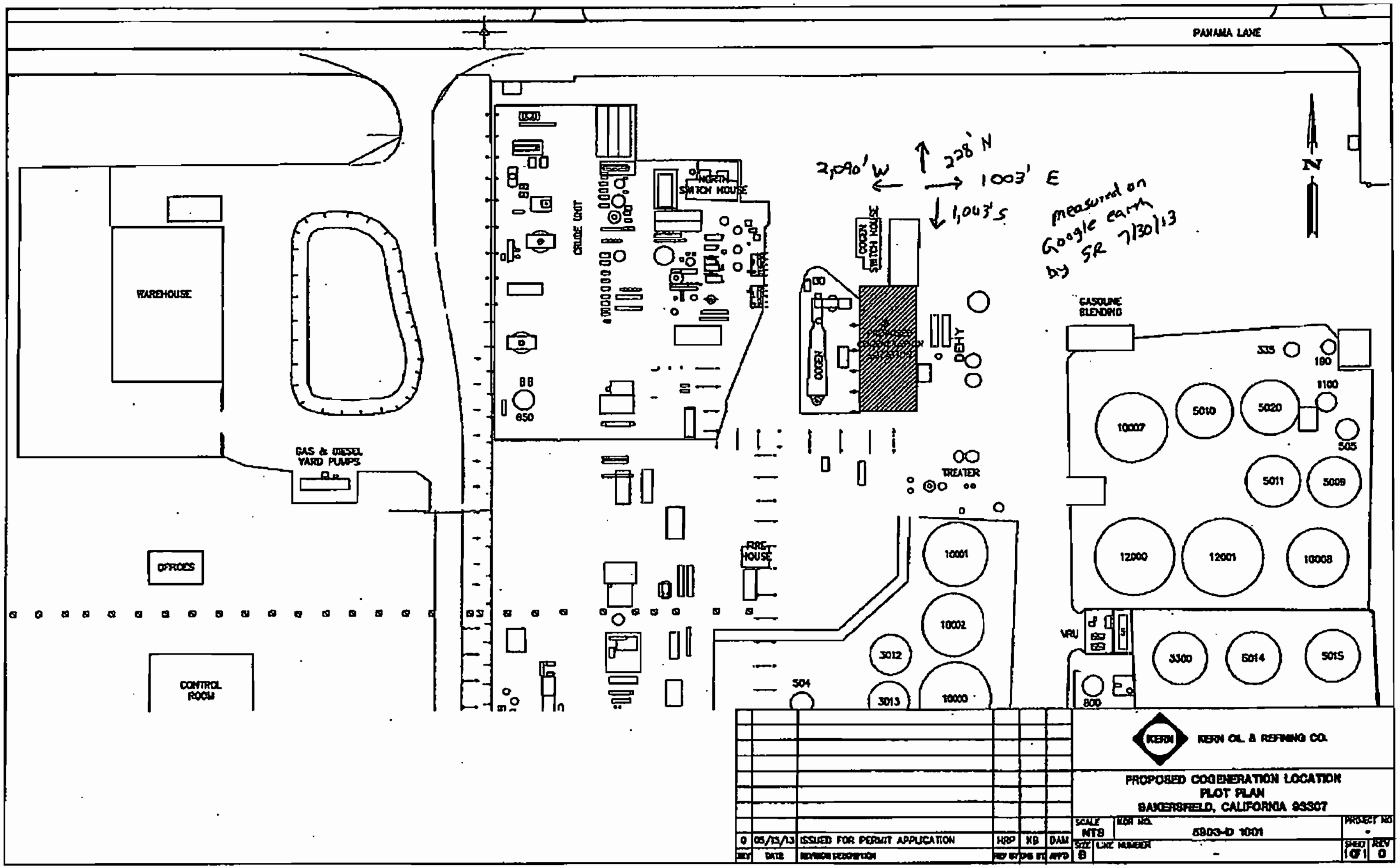
From: Kyle Melching
Sent: Wednesday, July 31, 2013 2:23 PM
To: Steven Roeder
Subject: FW: Attached Image

So, the Hourly PM2.5 is not passing. To pass we need a number below 1.2. Currently we are at 3.22. I see that stack height is already pretty high, but the velocity is low. Is 18 ft/sec correct? Also, I've attached a picture of the facilities boundaries that we've used to model an AAQA before and was curious if this is still correct? Not sure if the facility had purchased any extra land that would extend the distance to the boundaries for this source.

Thanks!

Kyle Melching
Air Quality Specialist
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Ave., Fresno, CA 93726
Phone: 559-230-5894

From: Centralcopier
Sent: Wednesday, July 31, 2013 2:23 PM
To: Kyle Melching
Subject: Attached Image


PANAMA LANE
N
WAREHOUSE
GAS & DIESEL YARD PUMPS
OFFICES
CONTROL ROOM
CRUDE UNIT
NORTH SWITCH HOUSE
650
COGEN SWITCH HOUSE
COGEN
PROPOSED COGENERATION LOCATION
DEHY
TREATER
FIRE HOUSE
504
GASOLINE BLENDING
335
180
1100
505
10007
5010
5020
5011
5009
12000
12001
10008
10001
10002
3012
3013
10000
VRU
3300
5014
5015
800
2,090' W
228' N
1003' E
1,043' S
measured on Google earth by SR 7/30/13
KERN
KERN OIL & REFINING CO.
PROPOSED COGENERATION LOCATION
PLOT PLAN
BAKERSFIELD, CALIFORNIA 93307
SCALE NTS
KERN NO. 5903-D 1001
PROJECT NO -
SIZE B
LINE NUMBER -
SHEET 1 OF 1
REV 0
0 05/15/13 ISSUED FOR PERMIT APPLICATION HRP NB DAM
REV DATE REVISION DESCRIPTION REV BY CHK BY APPD


2D 3D | Road Aerial Bird's eye | Labels
Brooks Ln
Hilltop Dr
Hoffman Ave
Weedpatch Hwy
E Panama Ln
E Panama Ln
E Panama Ln
184
Weedpatch Hwy

Print WorkSheet

Facility Name: ______________________________

Stack Diameter in Meters :	1.3716	Code:	1		
		Value:	54		1 = Inches
					2 = Feet
Stack Height in Meters :	19.812	Code:	2		
		Value:	65		
Stack Gas Temp ° K:	432.444445	Code:	3		3 = Degrees F
		Value:	319		4 = Degrees C
Stack Gas Velocity (M/Sec):	7.5777	Code:	6		5 = Ft/Min
		Value:	23724		6 = ACFM
					7 = DSCF
					8 = Ft/Sec
Nat Gas Rate in MMSCF:	Try Again	Code:			
		Value:			9 = BTU
					10 = SCF
Receptor Distance (m):	Try Again	Code:			
		Value:			

Codes

1 = Inches
2 = Feet
3 = Degrees F
4 = Degrees C
5 = Ft/Min
6 = ACFM
7 = DSCF
8 = Ft/Sec
9 = BTU
10 = SCF

PRIORITIZATION
FOR

KERN OIL & REFINING CO.
Project # 1133043
Region (S) Facility (37)

Emissions and Potency Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
2.63E-02	1.07E-02	1.48E-02

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor (Cancer = 1700, Acute = 1500, Chronic = 150)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance

	RP
0m < R < 100m	1.0
100m < R < 250m	0.25
250m < R < 500m	0.04
500m < R < 1000m	0.011
1000m < R < 1500m	0.003
1500m < R < 2000m	0.002
R > 2000m	0.001

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * 1700

Acute Score:
TS(t) = [EHR(t) / AREL(t)] * RP * 1500

Chronic Score:
TS(t) = { ([EYR(t) / Hours Of Operation] / CREL(t)) * RP * 150 }

Dispersion Adjustment Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
9.74E-03	4.00E-03	5.57E-03

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor (Cancer = 28, Acute = 25, Chronic = 2.5)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
SHA = Stack Height Adjustment (< 20m = 60, < 45m = 9, >= 45m = 1)
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance
H = Stack Height

For Stack - 0m <= H < 20m	RP	For Stack - 20m <= H < 45m	RP	For Stack - >= H < 45m	RP
0m < R < 100m	1.0	0m < R < 100m	1.0	0m < R < 100m	1.0
100m < R < 250m	0.25	100m < R < 250m	0.85	100m < R < 250m	1.0
250m < R < 500m	0.04	250m < R < 500m	0.22	250m < R < 500m	0.90
500m < R < 1000m	0.011	500m < R < 1000m	0.064	500m < R < 1000m	0.40
1000m < R < 1500m	0.003	1000m ≤ R < 1500m	0.018	1000m < R < 1500m	0.13
1500m < R < 2000m	0.002	1500m < R < 2000m	0.009	1500m < R < 2000m	0.066
R > 2000m	0.001	R > 2000m	0.006	R > 2000m	0.042

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * SHA * 28

Acute Score:
TS(t) = [EHR(t) / AREL(t)] * RP * SHA * 25

Chronic Score:
TS(t) = { ([EYR(t) / Hours Of Operation] / CREL(t)) * RP * SHA * 2.5 }

PRIORITIZATION
FOR

KERN OIL & REFINING CO.
Project # 1133043
Region (S) Facility (37)

DEVICE NUMBER 151
DEVICE NAME 4.6 MW NG Turbine

CAS NUMBER	POLLUTANT NAME	LBS/HOUR	LBS/YEAR	Emissions and Potency Method — Prioritization Scores: CANCER	CHRONIC	ACUTE	Desperslon Adjustment Method — Prioritization Scores: CANCER	CHRONIC	ACUTE
106990	1,3-Butadiene	3.52E-05	2.97E-01	3.44E-03	1.02E-05		1.27E-03	3.83E-06	
75070	Acetaldehyde	3.27E-03	2.76E+01	5.08E-03	1.36E-04	4.18E-04	1.88E-03	5.09E-05	1.57E-04
107028	Acrolein	5.24E-04	4.42E+00		8.68E-03	1.26E-02		3.26E-03	4.71E-03
71432	Benzene	7.44E-05	6.29E-01	1.24E-03	7.20E-06	3.44E-06	4.60E-04	2.70E-06	1.29E-06
100414	Ethyl benzene	2.62E-03	2.21E+01	3.76E-03	7.60E-06		1.39E-03	2.85E-06	
50000	Formaldehyde	1.64E-03	1.38E+01	5.64E-03	1.05E-03	1.78E-03	2.09E-03	3.96E-04	6.69E-04
91203	Naphthalene	1.06E-04	8.99E-01	2.08E-03	6.86E-05		7.70E-04	2.57E-05	
1150	PAHs, total, with individ. components also reported	1.80E-04	1.52E+00						
75569	Propylene oxide	2.37E-03	2.00E+01	5.04E-03	4.59E-04	4.59E-05	1.87E-03	1.72E-04	1.72E-05
108883	Toluene	1.06E-02	8.99E+01		2.06E-04	1.72E-05		7.71E-05	6.47E-06
1330207	Xylenes (mixed)	5.24E-03	4.42E+01		4.34E-05	1.43E-05		1.63E-05	5.35E-06
			TOTALS FOR DEVICE 151	2.63E-02	1.07E-02	1.48E-02	9.74E-03	4.00E-03	5.57E-03

FILE: C:\HARP\PROJECTS\Projects July 2013-Dec 2013\Kern Oil and Refining\Rep_PMI.txt

EXCEPTION REPORT
(there have been no changes or exceptions)

RECEPTORS WITH HIGHEST CANCER RISK

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
32	GRID	6.04E-09	1.82E-04	3.60E-04	325973	3907131	11
33	GRID	5.49E-09	1.65E-04	3.28E-04	326033	3907120	11
31	GRID	4.60E-09	1.38E-04	3.29E-04	325965	3907029	11
34	GRID	4.45E-09	1.34E-04	3.04E-04	326031	3907023	11
35	GRID	4.06E-09	1.22E-04	2.95E-04	326017	3906980	11
30	GRID	3.66E-09	1.10E-04	2.98E-04	325966	3906940	11
42	GRID	3.44E-09	1.03E-04	2.54E-04	326234	3907000	11
41	GRID	3.38E-09	1.02E-04	2.51E-04	326163	3906932	11
40	GRID	3.16E-09	9.51E-05	2.42E-04	326229	3906930	11
29	GRID	3.12E-09	9.39E-05	2.78E-04	325978	3906868	11

RECEPTORS WITH HIGHEST CHRONIC HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
32	GRID	6.04E-09	1.82E-04	3.60E-04	325973	3907131	11
33	GRID	5.49E-09	1.65E-04	3.28E-04	326033	3907120	11
31	GRID	4.60E-09	1.38E-04	3.29E-04	325965	3907029	11
34	GRID	4.45E-09	1.34E-04	3.04E-04	326031	3907023	11
35	GRID	4.06E-09	1.22E-04	2.95E-04	326017	3906980	11
30	GRID	3.66E-09	1.10E-04	2.98E-04	325966	3906940	11
42	GRID	3.44E-09	1.03E-04	2.54E-04	326234	3907000	11
41	GRID	3.38E-09	1.02E-04	2.51E-04	326163	3906932	11
40	GRID	3.16E-09	9.51E-05	2.42E-04	326229	3906930	11
29	GRID	3.12E-09	9.39E-05	2.78E-04	325978	3906868	11

RECEPTORS WITH HIGHEST ACUTE HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
59	GRID	1.65E-09	4.95E-05	4.25E-04	325968	3907635	11
60	GRID	1.98E-09	5.95E-05	4.19E-04	326006	3907586	11
57	GRID	9.14E-10	2.75E-05	4.05E-04	325601	3907880	11
79	GRID	8.91E-10	2.68E-05	3.94E-04	325972	3907770	11
61	GRID	1.80E-09	5.42E-05	3.90E-04	326060	3907584	11
62	GRID	1.34E-09	4.02E-05	3.69E-04	326032	3907662	11
64	GRID	1.15E-09	3.46E-05	3.61E-04	326055	3907691	11
32	GRID	6.04E-09	1.82E-04	3.60E-04	325973	3907131	11
65	GRID	1.53E-09	4.60E-05	3.46E-04	326114	3907598	11
71	GRID	1.10E-09	3.29E-05	3.44E-04	326088	3907693	11

Facility Summary: KERN OIL & REFINING

REGION: S

FACID: 37

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores CANCER	Prioritization Scores ACUTE	Prioritization Scores CHRONIC	Risk Scores CANCER	Risk Scores ACUTE	Risk Scores CHRONIC
950451	2	2	14.1 MMBTU/HR RERUN UNIT	2.344	0.006	0.017	0.00E+00	0.00E+00	0.00E+00
950451	4	1	PLATFORMER UNIT FOR REFORMULA	0.031	0.005	0.004	0.00E+00	0.00E+00	0.00E+00
950451	46	1	NAPHTHA & MINERAL SPIRITS LOADI	1.859	0.005	0.013	0.00E+00	0.00E+00	0.00E+00
950451	90	0	NAPHTHA & MINERAL SPIRITS LOADI	0.002	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
950451	91	0	GASOLINE STORAGE TANK #2501 W/	0.001	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
Project Totals				4.237	0.017	0.034	0.00E+00	0.00E+00	0.00E+00
961075	95	0	TANK (NO HAPS)	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
961075	96	0	TANK (NO HAPS)	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
971122	97	0	STORAGE TANK (ORGANIC LIQUID)	0.088	0.000	0.001	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.088	0.000	0.001	0.00E+00	0.00E+00	0.00E+00
971363	1	4	NG HEATER	0.009	0.032	0.011	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.009	0.032	0.011	0.00E+00	0.00E+00	0.00E+00
980612	21	4	TANK	0.083	0.028	0.012	5.75E-09	1.00E-04	1.00E-04
980612	22	4	TANK	0.083	0.028	0.012	5.75E-09	1.00E-04	1.00E-04
Project Totals				0.166	0.056	0.025	1.15E-08	2.00E-04	2.00E-04
990354	102	1	FIXED ROOF ORGANIC LIQUID STORA	0.051	0.000	0.000	5.54E-08	0.00E+00	0.00E+00

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores CANCER	Prioritization Scores ACUTE	Prioritization Scores CHRONIC	Risk Scores CANCER	Risk Scores ACUTE	Risk Scores CHRONIC
Project Totals				0.051	0.000	0.000	5.54E-08	0.00E+00	0.00E+00
1000982	23	5	STORAGE TANK 5008 (REMODELED 2	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1000982	107	0	LOADING RACK (REMODELED 2010)	0.146	0.050	0.022	3.44E-07	1.60E-01	0.00E+00
1000982	108	0	TANK (REMODELED 2010)	0.146	0.050	0.022	0.00E+00	0.00E+00	0.00E+00
1000982	109	0	TANK (REMODELED 2010)	0.146	0.050	0.022	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.437	0.151	0.066	3.44E-07	1.60E-01	0.00E+00
1001372	111	0	CRUDE OIL STORAGE TANK	0.004	0.001	0.001	4.11E-07	1.37E-02	1.60E-03
Project Totals				0.004	0.001	0.001	4.11E-07	1.37E-02	1.60E-03
1010295	114	0	NG TURBINE	2.714	0.092	0.260	0.00E+00	0.00E+00	0.00E+00
Project Totals				2.714	0.092	0.260	0.00E+00	0.00E+00	0.00E+00
1021207	4	7	SPLITTER REBOILER HEATER	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1021207	116	0	SPLITTER REBOILER HEATER	9.172	4.068	1.973	1.70E-07	0.00E+00	0.00E+00
Project Totals				9.172	4.068	1.973	1.70E-07	0.00E+00	0.00E+00
1021208	77	8	HYDROTREATER UNIT CHARGE/REB	30.261	12.494	6.217	0.00E+00	0.00E+00	0.00E+00
Project Totals				30.261	12.494	6.217	0.00E+00	0.00E+00	0.00E+00
1040960	1	10	Two 60 MMBtu/hr Process Heater	74.747	32.035	15.940	1.78E-06	9.00E-02	3.00E-02
Project Totals				74.747	32.035	15.940	1.78E-06	9.00E-02	3.00E-02
1040995	77	10	HYROTREATER - CHARGE/STRIPPER	8.386	3.444	1.709	2.30E-07	1.00E-02	0.00E+00
1040995	118	0	NAPTHA PRETREATMENT - CHARGE/	17.254	6.904	3.438	7.80E-07	9.00E-02	1.00E-02
1040995	119	0	REFORMER UNIT	41.282	16.694	8.211	1.44E-06	2.20E-01	6.00E-02
1040995	120	0	AMINE SYSTEM	0.162	0.057	0.024	2.50E-08	5.25E-02	0.00E+00
1040995	121	0	SOUR WATER SYSTEM	0.128	0.041	0.019	2.50E-08	5.25E-02	0.00E+00

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores CANCER	ACUTE	CHRONIC	Risk Scores CANCER	ACUTE	CHRONIC
1040995	122	0	SULFUR RECOVERY PLANT	6.612	2.590	1.261	2.50E-08	5.25E-02	0.00E+00
Project Totals				73.823	29.729	14.662	2.53E-06	4.77E-01	7.00E-02
1043196	123	0	DICE (RERUN)	6.758	0.000	3.822	5.10E-07	0.00E+00	0.00E+00
Project Totals				6.758	0.000	3.822	5.10E-07	0.00E+00	0.00E+00
1043894	8	20	Fugitives from VRS	0.006	0.003	0.001	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.006	0.003	0.001	0.00E+00	0.00E+00	0.00E+00
1044525	116	2	(CO MODELING ONLY) REBOILER HE	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1064331	3	8	Unifiner heaters	0.035	0.014	0.007	0.00E+00	0.00E+00	0.00E+00
1064331	4	16	Platformer Heaters	0.085	0.035	0.017	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.119	0.049	0.024	0.00E+00	0.00E+00	0.00E+00
1064662	130	0	74,000 BBL ORGANIC LIQUID STORAG	0.121	0.041	0.018	2.30E-08	0.00E+00	0.00E+00
1064662	131	0	74,000 BBL ORGANIC LIQUID STORAG	0.000	0.000	0.000	2.30E-08	0.00E+00	0.00E+00
Project Totals				0.121	0.041	0.018	4.60E-08	0.00E+00	0.00E+00
1074576	138	0	ORGANIC LIQUID LOADING RACK (<SI	0.005	0.002	0.001	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.005	0.002	0.001	0.00E+00	0.00E+00	0.00E+00
1084912	8	25	VAPOR RECOVERY SYSTEM (BELOW	0.001	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1084912	125	2	TANK ((BELOW SIGNIFICANCE LEVEL	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.001	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1092006	94	4	RAILCAR LOADING/UNLOADING RACK	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores CANCER	Prioritization Scores ACUTE	Prioritization Scores CHRONIC	Risk Scores CANCER	Risk Scores ACUTE	Risk Scores CHRONIC
1095174	8	27	LOADING AREAS & REFINERY VAPOR	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1095174	145	0	ORGANIC LIQUID STORAGE TANK	0.004	0.001	0.001	0.00E+00	0.00E+00	0.00E+00
1095174	146	0	ORGANIC LIQUID STORAGE TANK	0.004	0.001	0.001	0.00E+00	0.00E+00	0.00E+00
Project Totals				0.008	0.002	0.001	0.00E+00	0.00E+00	0.00E+00
1100705	2	8	MODIFIY - RERUN UNIT WITH 30 MMB	0.011	0.003	0.001	6.31E-09	1.96E-04	5.73E-05
Project Totals				0.011	0.003	0.001	6.31E-09	1.96E-04	5.73E-05
1103680	94	6	TRANSFER PUMPS	0.000	0.000	0.000	3.35E-09	1.24E-03	3.68E-05
Project Totals				0.000	0.000	0.000	3.35E-09	1.24E-03	3.68E-05
1111779	8	29	Organic Materials Loading Rack	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1111779	147	0	Organic Materials Loading Rack	0.291	0.001	0.002	5.48E-07	1.73E-03	2.93E-04
Project Totals				0.291	0.001	0.002	5.48E-07	1.73E-03	2.93E-04
1114091	1	13	Crude Unit Fugitive (Reduction)	-0.224	-0.001	-0.002	-4.94E-09	-3.79E-05	-4.12E-06
1114091	7	5	Flare Compressor Equip. Fugitive	0.485	0.001	0.004	1.05E-07	4.27E-04	6.06E-05
Project Totals				0.262	0.001	0.002	1.00E-07	3.89E-04	5.65E-05
1114600	7	6	PURGE GAS SYSTEM - ADD C-02 COM	0.016	0.000	0.000	2.34E-07	5.01E-04	1.35E-04
Project Totals				0.016	0.000	0.000	2.34E-07	5.01E-04	1.35E-04
1120301	114	5	COGEN SYSTEM W/ NG FIRED SOLAR	0.033	0.007	0.004	1.85E-08	2.78E-03	5.57E-04
Project Totals				0.033	0.007	0.004	1.85E-08	2.78E-03	5.57E-04
1121674	111	6	55,000 BBL ORGANIC LIQUID STORAG	0.359	0.001	0.003	5.29E-08	6.64E-05	2.83E-05
Project Totals				0.359	0.001	0.003	5.29E-08	6.64E-05	2.83E-05
1123575	148	0	54,000 BBL FLOATING ROOF TANK	0.033	0.000	0.000	2.26E-08	2.80E-05	1.30E-05

PROJECT	Unit ID	MOD #	EQUIPMENT	Prioritization Scores CANCER	ACUTE	CHRONIC	Risk Scores CANCER	ACUTE	CHRONIC
Project Totals				0.033	0.000	0.000	2.26E-08	2.80E-05	1.30E-05
1130397	149	0	4 MMSCF/DAY LPG RECOVERY UNIT	0.037	0.000	0.000	1.60E-07	1.70E-04	3.53E-05
Project Totals				0.037	0.000	0.000	1.60E-07	1.70E-04	3.53E-05
1131410	8	31	ORGANIC LIQUID LOADING AREAS W/	0.000	0.000	0.000	0.00E+00	0.00E+00	0.00E+00
1131410	150	0	3000 BBBL ORGANIC LIQUID STORAG	0.002	0.001	0.000	8.27E-09	1.37E-03	9.11E-05
Project Totals				0.002	0.001	0.000	8.27E-09	1.37E-03	9.11E-05
1133043	151	0	4.6 MW NG Turbine	0.026	0.015	0.011	6.04E-09	4.25E-04	1.82E-04
Project Totals				0.026	0.015	0.011	6.04E-09	4.25E-04	1.82E-04
Facility Totals				203.797	78.800	43.081	7.01E-06	7.50E-01	1.03E-01

AAQA for Kern Oil and Refining (S-37-151-0)
All Values are in Micrograms per Cubic Meter

	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
STCK1	1.6	1.7E-01	2.3	1.5	0.5	0.4	0.2	5.3E-02	0.42	1.24E-01
Background	122.4	3.3E+01	4,077.5	2,563.0	159.8	133.2	71.9	2.7E+01	267.00	8.30E+01
Facility Totals	124.0	32.7	4,079.8	2,564.5	160.3	133.6	72.1	26.7	267.4	83.1
AAQS	188.7	56.0	23,000.0	10,000.0	195.0	1,300.0	105.0	80.0	50.0	30.0
	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass	~~Fail~~ PASS	~~Fail~~ PASS

EPA's Significance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	1.0	2000.0	500.0	0.0	25.0	5.0	1.0	5.0	1.0

PM 2.5
24 Hour
1.2
PASS

PM 2.5
Annual
6.3
PASS

*Since 5-years of metereological data were used, an adjustment factor of 1.75 for Bakersfield was applied to the annual average concentrations for the devices modeled.

AAQA Emission (g/sec)

Device	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
STCK1	9.13E-02	9.14E-02	1.33E-01	1.33E-01	2.89E-02	2.89E-02	2.89E-02	2.88E-02	6.77E-02	6.76E-02

*Since 5-years of metereological data were used, an adjustment factor of 1.75 for Bakersfield was applied to the annual average concentrations for the devices modeled.

AERMOD Non-Regulatory Option Checklist (ARM / OLM / PVMRM)

Approved	Site Specific Parameters Items that are required for a Case – By – Case determination are noted with an *	
	Facility Information	
	Permit ID	S-37
	Name	Kern Oil and Refining
	Address	7724 E. Panama Ln.
	City / State	Bakersfield, CA
Comments		
	Project Information	
	Project ID	S-1133043
	Unit ID / Mod (s)	151-0
	Description	4.6 MW NG Turbine
Comments		
	Modeling Information*	
	Model	EPA AERMOD Version (8.1.0), AERMOD 11059
	Operating Scenario	8760 hr/yr
	Met Data	23155
	Site Name	Bakersfield
	Years	Start: 2005 End: 2009
	Type	NWS
	Terrain	Flat
	Site Location	Zone: UTME: 314.122 UTMN: 3923.02817
	Ozone Limiting	Not Required
	Source Parameter	See Tables Below
	Background Site	3145
	Name	Bakersfield-Golden State Highway
	Location	Zone: UTME: 317.24142 UTMN:3917.63364
	Years	Start: End:
	Location Type	Rural
	Distance From Project (km)	
Comments		
	Final Results*	
	Averaging Period / Concentration (Background + Model)	SIL: Local Hour ARM: 0.9 1st Run AAQA Passes
Comments		
	Conclusion* It has been determined that enough information has been provided to conclude that OLM or PVMRM were not required for the above modeling scenario.	
	Supervisor Name	Ester Davila
	Supervisor Signature	[signature]
Comments		

Source Parameter:

Each different source that is modeled should have a separate table.

Analysis Parameters (Unit 151-0)			
Closest Receptor - Business (m)	431	Closest Receptor – Resident (m)	452
NG Usage (mmscf/hr)	0.082	NG Usage (mmscf/yr)	691.16
Release Height (m)	19.8	Gas Exit Temperature (K)	432
Stack Inside Diameter (m)	1.37	Gas Exit Velocity (m/s)	7.58

ATTACHMENT VI
Statewide Compliance Statement

Kern Oil & Refining Co.
7724 E. PANAMA LANE
BAKERSFIELD, CALIFORNIA 93307-9210
(661) 845-0761 FAX (661) 845-0330

July 16, 2013

Mr. Leonard Scandura
SJVAPCD
34946 Flyover Court
Bakersfield, CA 93308

**Subject: Kern Oil & Refining Co. – Compliance Certification
Project Application for Addition of 4.6 MW Cogeneration Unit**

Dear Mr. Scandura:

District Rule 2201, Section 4.15.2, requires that an owner or operator proposing a Federal Major Modification 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 are either in compliance or on a schedule for compliance with all applicable emission limitations and standards. This letter certifies compliance for Kern Oil & Refining Co.

Kern Oil & Refining Co. (Kern) is the sole owner and operator of a petroleum refining facility, ID S-37, located at 7724 E. Panama Lane in Bakersfield, CA. Kern has Notices of Violation outstanding; however all issues associated with these are currently being addressed.

This certification is made on information and belief and is based upon a review of Kern's major source facility by employees who have responsibility for compliance and environmental requirements. This certification is as of the date of its execution.

If you have any questions, please call Melinda Hicks, EHS Manager, at (661) 845-0761.

Sincerely,

Bruce Cogswell

Bruce Cogswell
VP Manufacturing

cc: Melinda Hicks
Joe Selgrath

ATTACHMENT VII
Title V Compliance Certification Form

RECEIVED
JUL 1 8 2013
SJVAPCD
Southern Region

San Joaquin Valley
Unified Air Pollution Control District

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

[√] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

COMPANY NAME: KERN OIL & REFINING CO.	FACILITY ID: S- 37
1. Type of Organization:[√] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility	
2. Owner's Name:	
3. Agent to the Owner:	

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

BC Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

BC Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

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

BC Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Bruce Cogswell
Signature of Responsible Official

7/17/2013
Date

Bruce Cogswell
Name of Responsible Official (please print)

VP Manufacturing
Title of Responsible Official (please print)

ATTACHMENT VIII
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-37-151-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: KERN OIL & REFINING CO.
MAILING ADDRESS: 7724 E PANAMA LANE
BAKERSFIELD, CA 93307-9210

LOCATION: PANAMA LN & WEEDPATCH HWY
BAKERSFIELD, CA 93307-9210

EQUIPMENT DESCRIPTION:
4.6 MW SOLAR CENTAUR MODEL 50-T6200S NATURAL GAS-FIRED GAS TURBINE ENGINE WITH DRY LOW-NOX COMBUSTORS AND 21.2 MMBTU/HR DUCT BURNER SYSTEM, AND WASTE HEAT RECOVERY SYSTEM, WITH SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AMMONIA INJECTION AND OXIDATION CATALYST (OR EQUIVALENT)

CONDITIONS

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. 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] Federally Enforceable Through Title V Permit
4. 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] Federally Enforceable Through Title V Permit
5. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services
S-37-151-0 : Sep 24 2013 10:16AM -- EDGEHILR : Joint Inspection NOT Required

6. 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] Federally Enforceable Through Title V Permit

7. No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (12/17/92), by using EPA method 9. If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)] Federally Enforceable Through Title V Permit

8. 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]

9. Cogeneration unit must be operated at least 228 feet from the property boundary. [District Rule 4102]

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

11. Gas turbine and duct burner shall be fired on natural gas. [District Rule 2201] Federally Enforceable Through Title V Permit

12. A totalizing mass or volumetric fuel flow meter shall be utilized and maintained to calculate the amount of gas combusted based on measured flow meter parameters (fuel pressure and temperature), gas composition, and HHV of the fuel. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

13. Combined turbine and duct burner total heat input shall not exceed 1,963.2 MMBtu/day nor 691,164 MMBtu/year. [District Rule 2201] Federally Enforceable Through Title V Permit

14. Sulfur content of natural gas in the fuel being combusted shall not exceed 1.0 grains/100 scf. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801] Federally Enforceable Through Title V Permit

15. Emissions from the cogeneration system, except during periods of startup and shutdown, shall not exceed any of the following limits: 2.5 ppmvd NO_x (0.0092 lb/MMBtu) @ 15% O_2 referenced as NO_2; 6.0 ppmvd CO (0.0134 lb/MMBtu) @ 15% O_2; 0.0068 lb-PM10/MMBtu; 2.0 ppmvd VOC (0.0026 lb/MMBtu) referenced as methane. NO_x and CO emission limits are based on 3-hour rolling average period. If unit is in either startup, shutdown, or black start mode during any portion of a clock hour, the unit will not be subject to the ppmvd limits for NO_x and CO during that clock hour. [District Rules 2201,4201, and 4703] Federally Enforceable Through Title V Permit

16. Ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24-hour average period. [District Rule 2201] Federally Enforceable Through Title V Permit

17. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703] Federally Enforceable Through Title V Permit

18. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rule 4703] Federally Enforceable Through Title V Permit

19. Source testing to determine compliance with the NO_x, CO, and NH_3 emission rates (ppmvd @ 15% O_2) during normal operation shall be conducted with the GTE and duct burner firing concurrently and with the duct burner fired solely within 90 days of initial startup under this permit and annually thereafter. [District Rule 2201 and 40 CFR 60.4400(a] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

20. Unit shall demonstrate compliance annually with NOx and CO emissions limits. An annual demonstration of compliance with the turbine in operation is not required in any year in which the turbine is not operated at all in the preceding 12 months, in such case, the unit shall be compliance source tested within 60 days of resumption of operation of the turbine. [40 CFR 60.4340 and District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

21. 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] Federally Enforceable Through Title V Permit

22. Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081] Federally Enforceable Through Title V Permit

23. For the purpose of determining compliance with the emissions limits (ppmvd @ 15% O2) during normal operation in this permit, the arithmetic mean of three test runs shall apply, unless two of the three results are above an applicable limit. If two of three runs are above the applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 1081] Federally Enforceable Through Title V Permit

24. The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO -EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and 02 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, and 40 CFR 60.4400 (1)(i)] Federally Enforceable Through Title V Permit

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

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

27. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rule 1081] Federally Enforceable Through Title V Permit

28. The owner or operator shall submit a written report of continuous fuel H2S monitoring for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess H2S limits, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the monitor was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [40 CFR 60.4375(a) and 60.4395] Federally Enforceable Through Title V Permit

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

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

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CONDITIONS CONTINUE ON NEXT PAGE

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

32. The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, O2, and NH3 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

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

34. 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 2201 and 4703] Federally Enforceable Through Title V Permit

35. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2 and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% 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 2201 and 4703] Federally Enforceable Through Title V Permit

36. 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. [40 CFR 60.4330(a)(2), 60.102a(g)(1)(ii), 60.104a, and District Rules 2201 and 4801] Federally Enforceable Through Title V Permit

37. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [40 CFR 60.108a and District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

38. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, duration of each start-up and each shutdown time period; and, on a monthly basis, fuel HHV. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

39. Prior to operating equipment under this Authority to Construct, permittee shall surrender emission reduction credits for the following quantities of emissions: NOx: 2,385 lb/quarter; SOx: 739 lb/quarter; PM10: 1,763 lb/quarter, and VOC: 674 lb/qtr. 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 . [District Rule 2201] Federally Enforceable Through Title V Permit

40. ERC Certificate Numbers C-1191-2, S-2387-5, S-2649-4, and S-3806-1 (or certificates split from theses certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

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